Response Action Contract
Contract No. 68-W-98-228

EPA United States Environmental Protection Agency
REGION 10

DRAFT

Wyckoff/Eagle Harbor Superfund Site Soil and Groundwater Operable Units

Actions Needed to Restart Steam Pilot

April 2004

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in association with
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EPA Contract Number: 68-W-98-228
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Bellevue, Washington

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Introduction

The Wyckoff/Eagle Harbor Superfund site is located on the east side of Bainbridge Island, in central Puget Sound, Washington (Figure 1). This was the site of a former wood-treating facility. From the early 1900s through 1988, a succession of companies treated wood at the Wyckoff property for use as railroad ties and trestles, telephone poles, pilings, docks, and piers. The wood-preserving plant was one of largest in the United States, and its products were sold throughout the nation and the rest of the world. Operations at the site involved the use of creosote, pentachlorophenol, solvents, gasoline, antifreeze, fuel and waste oil, and lubricants. Over the years, an estimated one million gallons of creosote and other contaminates were spilled. Most of that contamination still exists in the soil and groundwater operable units.

A Record of Decision (ROD) was issued in February 2000. In accordance with this, EPA and the USACE implemented a thermal remediation pilot project in 2002 and 2003 to test the effectiveness of thermal remediation over a representative one-half-acre test area. The steam pilot was placed into operation in the fall of 2002 and was shutdown early due to a variety of equipment problems in April 2003. The results of this shortened pilot test will be presented in a separate report titled “Thermal Remediation Pilot Study Summary Report,” that is currently being compiled by the USACE.

The purpose of this report is to define what would need to be done to re-start the steam pilot at the Wyckoff site. The information contained in this document is a compilation of input from the entire Wyckoff team regarding what needs repair or modification and what is working well. This includes the USACE staff that have knowledge of the pilot operation, the site operations staff, and the team technical staff.

Two scenarios are considered: one to do the minimum required to get the pilot running again reliably, and the other to enhance the original steam pilot to strive for more complete contamination removal. The first scenario covers what needs to be done to resume the steam pilot test using as much of the existing equipment as possible. This would be at essentially the same capacity and configuration as the original pilot, but with appropriate repairs and modified naphthalene handling scheme so that the pilot would be able to operate more reliably.

The second scenario is based on one possibility for adding thermal energy to achieve more uniform heating above the aquitard and to heat the aquitard itself. Based on what has been learned to date, it is now felt that additional heat would be needed to mobilize contamination in or near the aquitard. (Additional information regarding the need for additional heating will be presented in the “Thermal Remediation Pilot Study Summary Report.”) Additional heating would increase the likelihood that the steam pilot would achieve the clean up levels anticipated in the ROD over the entire steam pilot test area. This scenario includes all of the things necessary to restart the pilot that were included in the first scenario, plus additional vacuum pump capacity, a larger thermal oxidizer, additional heating locations above the aquitard, steam injection points below the aquitard, and additional instrumentation.

There are many issues and impacts to the community that would result from full-scale thermal remediation of the entire site. A discussion of these issues and impacts are included as a part of a separate document, entitled "Wyckoff Bainbridge Island Engineering Evaluation / Cost Analysis."

Included below are brief descriptions of each of the main systems that comprise the Wyckoff steam pilot. More detailed descriptions of the required specific corrections and the estimated capital costs are included in Table 1 for the minimal pilot re-start and in Table 2 for the enhanced steam pilot.

Restart Pilot with Same Capacity and Minimum Corrections

Steam Generation and Injection System

The steam for the thermal remediation is generated by a 27,000 pound per hour diesel fueled boiler. The boiler water supply is a new deep well that is located on the western portion of the site that feeds a 1,500-gallon storage tank. The groundwater is softened and treated before being used by the boiler to generate steam. It is felt that the existing boiler has adequate steam capacity for the size of the pilot test area.

The steam is delivered to the pilot area injection wells via an insulated main steam header pipe with individual branches to each of the steam injection wells. The header includes provisions for expansion and contraction of the pipeline as its temperature changes.

The boiler is generally in good condition. However, there are two significant warranty issues that are being pursued with the contractor that provided the original equipment. First, the burner control does not reliably maintain a stable flame when the boiler ramps up and down to provide varying levels of steam. The second is that the deaerator tank interior coating has failed. Although both of these issues are currently being pursued, the outcome is not certain. If these items are not corrected under warranty, it will be a significant expense to make the needed corrections. One other significant issue with the boiler is that the boiler control software is not currently operating properly. This needs to be reviewed, updated, and a new operations and maintenance manual provided.

In addition to these items, there are a variety of relatively low-cost repairs and additions that should be done before re-starting the pilot. These include: repairing or adding flow meters, valves and minor piping changes, providing better personnel access to various locations on the boiler, improving the boiler building air quality, and other miscellaneous items. The steam delivery piping also requires some repairs. This includes pipe support work, new gauge taps, and a new muffler.

Vapor Extraction System

The vapor extraction system currently consists of two oil-based liquid-ring vacuum pumps that are used to draw as much as 800 ACFM of vapor from the pilot area through the horizontal vapor collection piping and the vertical extraction wells. During the previous steam pilot operation, the vapors were sent to the steam boiler for combustion. However for a variety of reasons, a new thermal oxidizer (Thermox) is planned for destruction of any further vapor that is removed from the site.

The vapor extraction system experienced the most significant troubles during the steam pilot. Seal material incompatibility caused the vapor heat exchanger to fail and many of the vapor collection lines became clogged with naphthalene crystals. More detail on the extent of the clogging, including photographs, can be found in Attachment 1, "Pilot Study Extraction Well/Vapor Recovery Video Results and NAPL Recovery Recommendations." Background on the chemistry causing with the clogging is included in Attachment 2, "Vapor Extraction During Vacuum Tests," and Attachment 3, "Polynuclear Aromatic Hydrocarbon Influence on System Design."

In addition, water was able to move up the vapor line and into the vacuum pumps where it displaced the liquid ring oil, which caused oil to be sent on to the boiler through the vapor line, and eventually caused the vacuum pumps to be shut down.

A concept for a new process to separate naphthalene and condensable compounds from the extracted vapor has been developed. This process also addresses the water knockout issue. A process flow diagram for this is presented as Figure 2. A direct contact cooler will be used to chill the extracted vapor to 180 °F. The cooling water will be recycled and cooled to 176 °F by the existing reconfigured shell & tube heat exchanger. A cooling tower will be used to chill the shell and tube heat exchanger cooling water to 75 °F. Therefore, the only additional waste stream to the WTP from the naphthalene removal process would be 3 gpm of blow down from the cooling tower. This process discussed in greater detail in Attachment 4, "Extracted Vapor Processing during Dynamic Underground Stripping."

Groundwater Extraction System

The groundwater extraction system consists of seven extraction wells spaced throughout the pilot area. These each have a compressed air-powered positive displacement pump. The extracted groundwater discharge lines go into a common header and the extracted water is conveyed to a tank in the boiler building before being pumped to the water treatment plant.

The extraction wells experienced varying but significant amounts of clogging as naphthalene and other compounds that were volatilized by the heat migrated into the wells and then cooled and solidified. One well is still clogged so badly that it cannot be disassembled before providing steam injection to free up the parts. More detail on this can be found in Attachment 1, "Pilot Study Extraction Well/Vapor Recovery Video Results and NAPL Recovery Recommendations."

The extraction wells require extensive re-work to make them serviceable for a resumed steam pilot. The wells will have to be unclogged and re-developed, the extraction well caps will require significant modification, the pumps will have to be re-installed with new parts, additional compressed air capacity will be needed, and steam injection lines in the wells will be needed to dissolve further clogging.

The water discharge system also requires significant modification. Needed components include a new oil/water separator and piping, two new extracted water heat exchangers with clean-out capability and waste handling provisions, modifications to various piping and valves, and some new pipelines.

Instrumentation

The instrumentation systems for the Wyckoff steam pilot ranged from simple analog pressure gauges and pump stroke counters to a state-of-the art fiber-optic temperature monitoring system.

There are a variety of temperature, pressure, and flow instruments in the steam generation system. Many are tied into the boiler PLC control system. These instruments are currently functional. However, there are ongoing serious issues related to the control and proper operation of the boiler and its burner. The USACE is working to either correct the deficiencies with the current system or to replace the boiler burner system entirely.

The instrumentation for the steam injection system consists of temperature and pressure gauges at each of the steam injection wells. The water extraction well instruments consist of pump stroke counters on the pumps, pressure gauges on the well pump supply air line, and pressure gauges on the extracted water line. The extracted vapor lines have temperature and vacuum gauges. There is an extensive temperature and pressure monitoring system that has been installed throughout the thermal remediation pilot volume. Most of the instruments were operating properly when the pilot was suspended. When re-starting the system, each instrument should be observed for proper operation and repaired or replaced, as appropriate.

Water Treatment System

For the purpose of this analysis, the assumption is made that by the time the steam pilot is re-started a new water treatment plant will have been constructed, and some form of cap will have been installed over the majority of the contaminated site. If this is the case, the water treatment plant would have the hydraulic capacity to treat the additional 35 gallon per minute anticipated flow from the resumed steam pilot. Note that the extracted groundwater flow is not anticipated to change significantly whether the minimal or enhanced steam pilot is implemented.

Even though the extracted thermal pilot groundwater will be cooled before being conveyed to the water treatment plant, it will still be considerably warmer than the groundwater flows from the wells outside the pilot area. This will require some modification to the water treatment plant. An allowance has been included for these modifications, since they have not been specifically identified at this point.

Waste Handling and Disposal

A resumed steam pilot effort will generate significant amounts of vapor, liquid, spent carbon and some miscellaneous solid wastes. The vapor will be sent to a new thermal oxidizer for destruction. The liquid product that is recovered will be will be combined with the product that is recovered from the former process area in a tank for that purpose. When enough volume has been collected to prompt a disposal event, the liquid product will be trucked to an appropriate disposal facility.

The amount of spent carbon will increase greatly during the steam pilot. It is not unusual for a load of carbon to last a year while extracting cold groundwater. During the thermal pilot, this is expected to increase to a carbon change every two weeks. The extracted groundwater carries a small amount of solids, which will be removed by the water treatment process. In addition, a variety of miscellaneous solid wastes will be generated by any future pilot operations, including contaminated PPE. When an appropriate quantity has been collected, a waste disposal event will be conducted to remove the product from the site and to take it to an appropriate disposal facility.

Operations Strategy

Before operations are resumed for the steam pilot, a detailed operations plan should be prepared. This should include the sequence for operations and criteria for making operational changes. It should also specifically address issues associated with the initial re-start of the pilot. For example, since the vapor collection piping is currently clogged with naphthalene, the pilot system should be re-started in a sequence that progressively unclogs the vapor piping from the vacuum pumps out to the well field.

Restart Enhanced Pilot with Increased Capacity

Experience with the initial steam pilot has raised some important issues related to the effectiveness of the thermal heating system and the ability to mobilize the product and to remove it from the ground. The following enhancements to the original steam pilot would increase the likelihood of contaminant removal to the clean up levels stated in the ROD.

It should be noted the scenario described below is only one possibility for providing additional heat to the formation. Before proceeding with an enhanced steam pilot, careful consideration should be given to the best way to accomplish this additional heating.

Listed below are the elements of this scenario:

- Add more steam injection points in the upper soil unit to provide more even heating.
- Add steam injection points below the aquitard to mobilize the product in the aquitard and that sitting just above the aquitard.
- Provide a new up-slope cut-off wall that would extend through the aquitard to block the up-hill migration of injected steam and product.
- Provide new extraction wells just below the bottom of the aquitard to extract any mobilized LNAPL.
- Provide new extraction wells in the shallow aquifer along the new south sheet pile wall.
- Add a third, larger, vacuum pump to provide additional vacuum capacity.

- Provide a larger thermal oxidizer that can operate at a temperature and residence time that assures destruction of all waste vapors, including dioxin and other contaminants that might be present or be produced during the remediation effort

These enhancements would provide a more robust thermal remediation system, but would still not guarantee success at meeting the cleanup standards. A more detailed description of these enhancements is included in Table 2.

Schedule and Cost

A summary level schedule for a re-started steam pilot is presented as Figure 3. This assumes 2 years for design and construction of the repairs and enhancements, 2 ½ years of active thermal remediation, and 1 year of cool down and polishing before the preparation of the final report. A longer polishing phase would likely produce more complete removal, however, the 1-year period is assumed at this point to reduce the operations and engineering costs. Although there would definitely be additional costs for the more robust enhanced steam pilot scenario, the timeframe should be approximately the same. So only one schedule scenario was prepared for this memo.

Table 3 contains the estimated capital, operations, engineering, and data management costs for each alternative. These estimated costs are very preliminary and are expected to be at an order-of-magnitude level. This level of accuracy is useful to get a sense of the various cost elements and for comparing alternatives. However, once a specific approach is selected, the chosen scenario should be better defined and a more accurate cost estimate should be prepared for that specific scenario. The total capital, operations, engineering, and data management cost for the minimal steam pilot is estimated to be in the range of $11.1 million. The enhanced steam pilot is estimated to have a total capital and operations cost of roughly $13.4 million.

Summary and Conclusions

Based on the items identified and assumptions made in this report, it would take about five and a half years and cost in the range of $11.1 million to complete the steam pilot with the minimum improvements needed and at the same capacity as the original. If it were desired to do a more robust thermal remediation pilot, it is estimated that it would take about the same time, but would cost significantly more for a total of about $13.4 million.

Experience gained from the initial pilot effort indicates that the heating from the current steam injection wells is neither likely to become uniform over the entire steam pilot area nor are the current injection wells likely to heat the zone just above the aquitard. So, if additional heating is not provided through some mechanism, it is unlikely that a resumed pilot would be successful at removing the contamination from the entire pilot area.

Figures

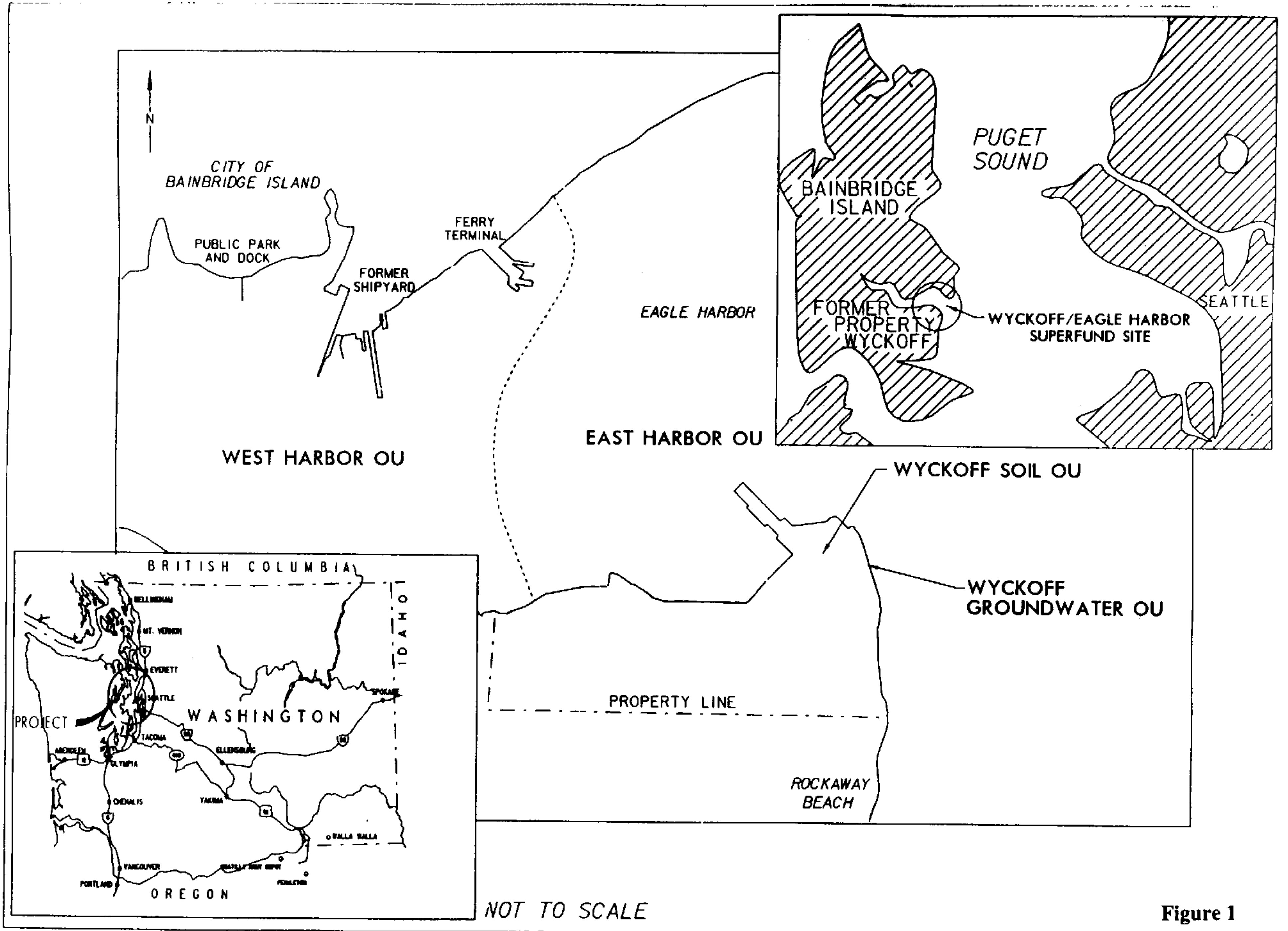
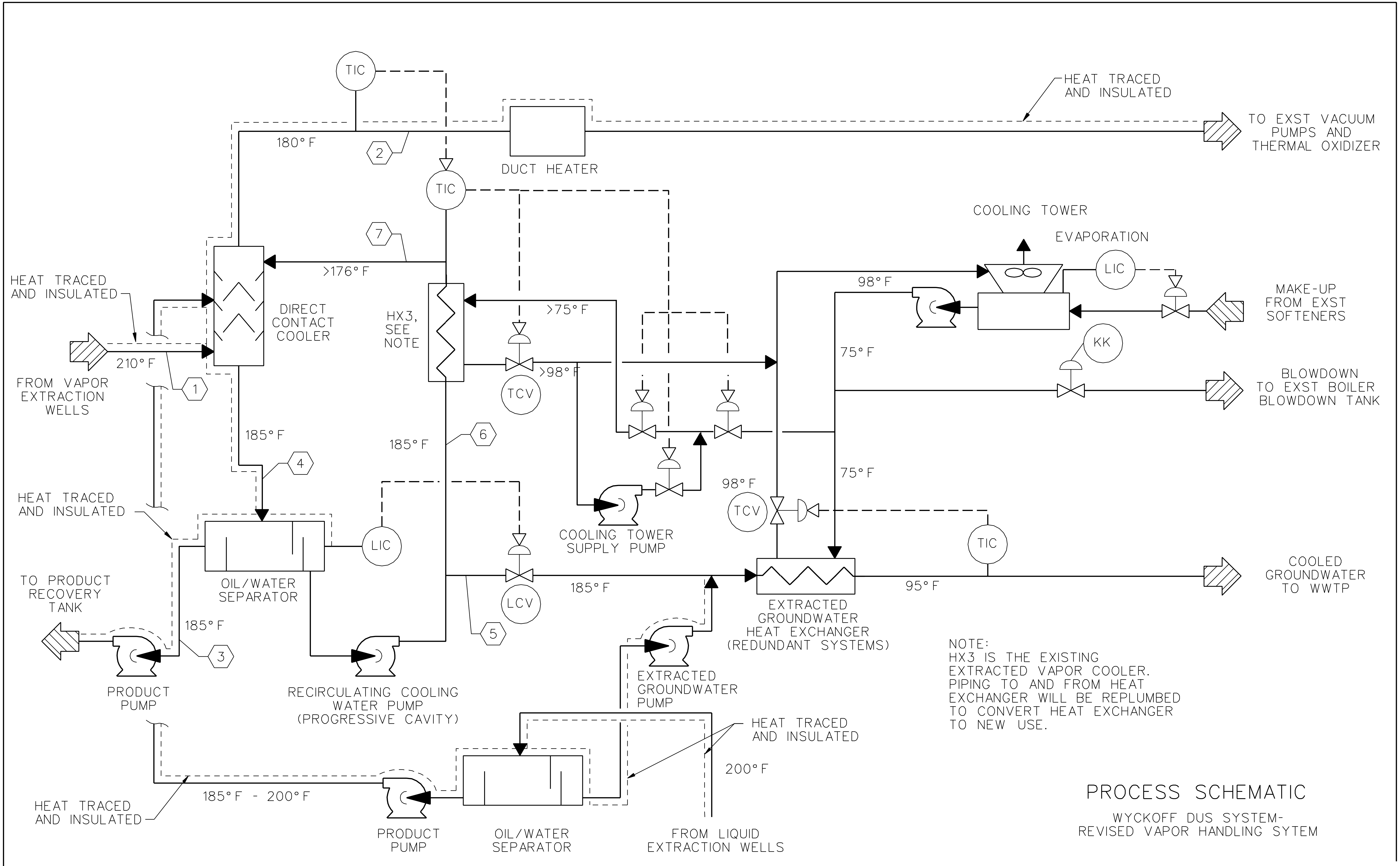


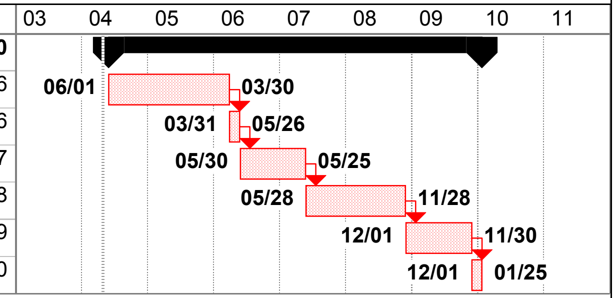
Figure 1

WYCKOFF/EAGLE HARBOR SUPERFUND SITE


TIC
HEAT TRACED
AND INSULATED
180° F
2
DUCT HEATER
TO EXST VACUUM
PUMPS AND
THERMAL OXIDIZER
TIC
7
>176° F
COOLING TOWER
EVAPORATION
LIC
HEAT TRACED
AND INSULATED
DIRECT
CONTACT
COOLER
HX3,
SEE
NOTE
>75° F
98° F
MAKE-UP
FROM EXST
SOFTENERS
210° F
FROM VAPOR
EXTRACTION
WELLS
1
TCV
>98° F
75° F
KK
BLOWDOWN
TO EXST BOILER
BLOWDOWN TANK
185° F
185° F
6
4
75° F
98° F
TCV
HEAT TRACED
AND INSULATED
LIC
COOLING TOWER
SUPPLY PUMP
TIC
OIL/WATER
SEPARATOR
185° F
LCV
TO PRODUCT
RECOVERY
TANK
EXTRACTED
GROUNDWATER
HEAT EXCHANGER
(REDUNDANT SYSTEMS)
95° F
COOLED
GROUNDWATER
TO WWTP
185° F
3
5
PRODUCT
PUMP
RECIRCULATING COOLING
WATER PUMP
(PROGRESSIVE CAVITY)
EXTRACTED
GROUNDWATER
PUMP
NOTE:
HX3 IS THE EXISTING
EXTRACTED VAPOR COOLER.
PIPING TO AND FROM HEAT
EXCHANGER WILL BE REPLUMBED
TO CONVERT HEAT EXCHANGER
TO NEW USE.
HEAT TRACED
AND INSULATED
200° F
185° F - 200° F
HEAT TRACED
AND INSULATED
PRODUCT
PUMP
OIL/WATER
SEPARATOR
FROM LIQUID
EXTRACTION WELLS
PROCESS SCHEMATIC
WYCKOFF DUS SYSTEM-
REVISED VAPOR HANDLING SYTEM
CH2MHILL

Wyckoff Thermal Pilot Restart Schedule

ID		Task Name	Duration	Start	Finish
1		**Wyckoff Thermal Pilot**	**1454 days**	**Tue 06/01/04**	**Mon 01/25/10**
2		Design and construct repairs and enhancements	465 days	Tue 06/01/04	Thu 03/30/06
3		Commission and test all thermal pilot equipment	41 days	Fri 03/31/06	Fri 05/26/06
4		Heat up formation and initial liquid/vapor extraction	252 days	Tue 05/30/06	Fri 05/25/07
5		Pressure cycling, HPO, etc	395 days	Mon 05/28/07	Fri 11/28/08
6		Cooldown and polishing	261 days	Mon 12/01/08	Mon 11/30/09
7		Project closeout and final data report	40 days	Tue 12/01/09	Mon 01/25/10



Date: Sat 04/24/04

Task		Rolled Up Task		External Tasks	
Critical Task		Rolled Up Critical Task		Project Summary	
Progress		Rolled Up Milestone		Group By Summary	
Milestone		Rolled Up Progress			
Summary		Split			

Figure 3

Tables

Table 1 - Wyckoff Steam Pilot Minimum Re-Start Action List

Status Date : 04.26.04

ITEM #	DEFIICIENCY	DESCRIPTION AND CORRECTION REQUIRED	PRIORITY	ORDER OF MAGNITUDE COST	COMMENTS
Operation					
O1	Develop revised process operating parameters.	Cover operational guidelines for all systems. Reevaluate the amount of compressed air available for the extraction pumps, available biological treatment capacity, needed additional GAC system capacity, steam volume, vacuum system capacity, projected volume of extracted groundwater, etc.	1	$50,000	
O2	Prepare new detailed steam pilot operations plan	Cover operational guidelines for all systems based on changes made to the original steam pilot systems.	1	$50,000	
O3	Interim maintenance	Prepare and execute interim preventative maintenance plan for valves, pumps, painting exposed metals, etc.	2	$50,000	
		Subtotal		**$150,000**	
Steam Generation and Injection					
S1	Boiler control	Correct the boiler PLC control issues.	1	$50,000	Review and correct PLC programming.
S2	Boiler burner control	Purchase, install, and test new "industry standard" burner control system.	1	$150,000	Current system does not run reliably and is high maintenance. If this is ultimately repaired under warranty, there would be no cost for the repairs.
S3	Deaeration tank flow meter	There is no reliable way to measure the amount of water going into the deaeration tank. Design and install an appropriate flow meter scheme.	2	$2,000	Simple, direct read meter.
S4	Pilot area steam isolation valve	Install a new 6-inch isolation valve on the steam line to the pilot area. This should be downstream of the tee that goes to the DA tank.	2	$5,000	This will allow proper heating of the water in the DA tank prior to sending steam to the pilot area.
S5	Boiler startup bypass line	Provide a 1-inch diameter bypass line with 1-inch diameter shutoff valve around the existing main steam shutoff valve. Make upstream connect between the existing steam check valve and the main shutoff valve.	2	$1,000	This will allow a slow startup of the boiler, which will result in less stress to the boiler and related equipment.
S6	Boiler building air quality	Provide an HVAC system to reduce potential for odors in boiler building.	2	$50,000	This is a health and safety issue.
S7	Sour gas line to boiler	Isolate the sour gas line from boiler (this will not be used.)	1	$1,000	Will require some minor piping modifications.
S8	Atomizing air compressor sheaves	Replace existing sheaves with larger set.	3	$500	Parts on hand. Very low cost.
S9	Deaerator tank coating	Remove tank, sandblast interior, apply 3-coat baked phenalic coating and reinstall.	1	$50,000	If this is ultimately done under warranty, there would be no cost for the repairs.
S10	Boiler water system cutoff switch	Add low pressure cutoff switch to water supply pumps for process water.	1	$6,000	Design is in process.
S11	Provide personnel access to top of boiler	Need access to operate stop check valves, root valve, and safety valves.	2	$20,000	
S12	Relocate root valve chain operator	The current configuration causes the chain to drag on the top and side of the boiler. Modify so that the chain runs freely.	2	$5,000	Can be operated now, but it is difficult and can wear the paint on the boiler shell.
S13	Boiler building insulation	Repair insulation that has pulled away from the roof and walls	1	$0	Should be done under warranty
S14	Steam end of the line muffler	Install a new muffler on the end of the steam bypass line	3	$5,000	
S15	Steam delivery piping supports	The supports and expansion joint for the steam piping do not allow adequate movement of the steam header as it expands and contracts with thermal changes. Re-design and reconstruct entire support amd expansion joint system.	2	$40,000	An allowance is included for this item, but the actual cost cannot be determined until the design for the support system is developed.
S16	Steam delivery piping taps	Taps were made by welding threaded nipples into steam piping. Replace all of these with appropriate half couplings welded into pipe.	2	$8,000	
S17	Boiler building work bench	Provide suitable work bench and cabinets in the boiler building for mechanical repairs	3	$1,000	
		Subtotal		**$394,500**	
Vapor Extraction System					
V1	New direct contact cooler	Design and construct new, direct contact vapor cooler and associated piping for chilled water, vapor, and condensed vapors.	1	$200,000	Direct cooling of vapor off well field.
V2	New oil-water separator	Design and construct a new oil water separator for the condensed vapors, with associated piping.	1	$120,000	
V3	New recovered product pumps	Design and construct two new recovered product pumps to convey product from the vapor system oil/water separator to the product tank.	1	$20,000	
V4	New recirculating cooling water pumps	Provide two new pumps and associated piping.	1	$20,000	

Table 1 - Wyckoff Steam Pilot Minimum Re-Start Action List

Status Date : 04.26.04

ITEM #	DEFIICIENCY	DESCRIPTION AND CORRECTION REQUIRED	PRIORITY	ORDER OF MAGNITUDE COST	COMMENTS
V5	Reconfigure existing shell and tube heat exchanger	Reconfigure piping to existing shell and tube heat exchanger to cool the water for the new direct contact cooler.	1	$10,000	
V6	New cooling tower and enclosure	Design and construct a new cooling tower, associated pumps and enclosure.	1	$165,000	This cools water for the extracted water heat exchangers and for the direct contact cooler heat exchanger.
V7	New duct heater	Design and construct new duct heater between direct contact cooler and vacuum pumps	1	$25,000	Required to keep the naphthalene in the vapor phase so that it does not clog vacuum pumps. Assume $25,000, including electrical costs
V8	New miscellaneous electrical allowance	Alolowance for electrical work associated with the new process equipment.	1	$80,250	Assume 15% of equipment cost
V9	New miscellaneous instrumentation and controls allowance	Allowance for instrumentation and control work associated with the new process equipment.	1	$80,250	Assume 15% of equipment cost
V10	New miscellaneous mechanical allowance	Allowance for mechanical work associated with the new process equipment.	1	$80,250	Assume 15% of equipment cost
V11	Rebuild vacuum pump	Change seal materials on one pump - test and re-start	1	$500	One pump has already been repaired.
V12	Thermox system capacity	Design and construct new Thermox unit of sufficient throughput and suitable for destruction of anticipated vapor contaminent concentrations.	1	$250,000	Need more capacity and existing thermox is not designed to be run at temperatures high enough to assure destruction of Dioxin. Assume installation of completely new unit. Assume 800 ACFM capacity.
V13	Horizontal vapor collection piping in pilot area	(1) Re-connect piping where it was cut for inspection by welding on new flanges. (2) Add steam injection at end of vapor collection pipes.	1	$10,000	(1) Welding can be done by OMI. Get test plug, fill with water, weld flanges, etc. - assume $2,000 (2) To be done by a contractor - assume $8,000
V14	Remove existing vapor knock out tank, piping and pumps.	Replaced by the new direct contact cooler.	1	$3,000	
V15	Vapor line flow meter between knock out tank and vacuum pumps	Currently have a 6-inch meter in an 8-inch line. Install a properly-sized flow meter.	2	$2,500	
V16	Vacuum pump rubber hoses	If possible, change the vacuum pump rubber hoses to a Viton hose. If not practical, obtain one complete set of replacement hoses for each pump.	2	$1,000	
V17	Vacuum pump No. 1 mechanical seals	Change the mechanical seals on LRVP 1 to Viton. (This has already been done on LRVP2.)	1	$1,000	
V18	Vacuum pump discharge piping	Re-work discharge piping on both vacuum pumps to allow changing the separator cartridges without disconnecting the entire vertical piping leg.	3	$2,500	
V19	Seal pilot area vapor cap penetrations	Perform vacuum test on pilot area. Design and construct cap penetration and edge seals.	2	$150,000	Boot all penetrations, place concrete seal along sheet pile wall.
V20	Insulate and steam trace extracted vapor lines.	Design and install a system to heat the extracted vapor lines to prevent solidification and plugging by naphthalene and other consitiuents in the piping.	1	$75,000	Wrap small steam tracing line around vapor pipe in a spiral and insulate.
V22	Prepare and execute a comprehensive approach to air emissions	Cover air emissions from the boiler, Thermox unit, open tanks, and other sources. Include monitoring type and schedule, agency coordination, and reporting.	1	$75,000	
		Subtotal		**$1,371,250**	
Water Extraction System					
W1	Extraction well pump test	Develop well pump test plan and perform pump test to determine the capacity of the pilot area groundwater flow.	2	$55,000	
W2	Unplug and re-develop all extraction wells	Inject steam to dissolve the naphthalene, use standard well development techniques to re-develop the gravel pack, and remove sediment in the bottom of the wells.	1	$100,000	This work should be completed prior to the vacuum test. EW01 is plugged solid.
W3	Extraction well cap modifications	Modify well caps to provide penetrations for slurper pumps and for steam injection.	1	$21,000	Assume 7 caps at $3000 each.
W4	Steam injection lines in the extraction wells	Design and install steam lines to remove naphthalene plugging.	1	$25,000	Requires running steam lines to each extraction well.
W5	Extraction well slurper pumps	Design and install piping in the extraction wells to provide backup slurper pump capability.	2	$35,000	Slurper pump will provide a backup in case the QED pump fails, will provide an adjustible intake for NAPL removal and will add capacity to QED pumps.
W6	Lower the groundwater extraction pumps.	Set the pumps so that they are as close to the bottom of the well as possible.	1	$40,000	Will require new air supply and discharge hoses. Assume will use QED materials.
W7	Extraction pump air supply capacity.	Add air supply capacity to the extraction well pumps. Either increase the size of the air supply piping, add air receivers in the pilot area, or a combination,	1	$10,000	Needed for proper operation of the pumps.

Table 1 - Wyckoff Steam Pilot Minimum Re-Start Action List

Status Date : 04.26.04

ITEM #	DEFIICIENCY	DESCRIPTION AND CORRECTION REQUIRED	PRIORITY	ORDER OF MAGNITUDE COST	COMMENTS
W8	New oil-water separator	Design and construct a new oil water separator for the extracted groundwater, with associated piping.	1	$120,000	Install this oil/water separator before the extracted groundwater heat exchangers.
W9	New recovered product pumps	Design and construct two new recovered product pumps to convey product from the groundwater oil/water separator to the product tank.	1	$20,000	
W10	New extracted groundwater heat exchangers	Provide two new shell and tube heat exchangers for the extracted groundwater. One will be in service while the second is being cleaned. Include a system for handling the wastes that collect in the heat exchangers.	1	$80,000	
W11	Old liquid/liquid heat exchangers	Remove the old heat exchangers.	1	$5,000	
W12	Extracted groundwater flow meter	The current flow meter have never worked correctly and is susceptible to naphthalene plugging. Purchase and install a new magnetic flow meter.	1	$7,500	
W13	Water Level Measurement	Evaluate current water level measurement system. Additional reference transducers will be required to correct for system vacuum impacts.	1	$15,000	
W14	TOC analyzer	Move analyzer to appropriate WTP location. Purchase and install new analyzer that is appropriate for measurement of constituents in liquid from boiler building to WTP after product separation.	1	$10,000	
W15	Extracted water piping in pilot area	Repair damaged flexible bellows in 2 places.	1	$5,000	
W16	Extracted water piping and drains	Slope piping to drain. Replace all extracted water piping drain valves and un-clog vertical drain piping. Add drains in all low spots. Design and construct a system to blow out the water with compressed air or to otherwise drain the extracted water piping when not in service to prevent damage during freezing weather.	1	$10,000	The current piping cannot be drained in freezing weather. Some drain legs have frozen and split. Others are clogged with product. Consider a different way to drain the pipe, since the drains rapidly clog.
W17	Replace check valves on extraction well discharges	Replace about half - of the 1-1/2" diameter check valves on extraction well discharge piping.	1	$2,000	These are clogged with product.
W18	Replace isolation valves on extraction well discharges	Replace all of the 1-1/2" diameter isolation valves on extraction well discharge piping.	1	$3,000	These are clogged with product. (??)
W19	New recovered product pumps	Design and construct two new recovered product pumps to convey product from the recovered liquid oil/water separator to the product tank.	1	$10,000	
W20	Gate and globe valves on steam supply lines in the field	Check, maintain and replace as needed	1	$1,000	
W21	Product pump overload protection	Change from electronic to mechanical overload protection.	2	$1,000	Electronic system is too sensitive and results in frequent nuisance tripping of the pumps.
W22	Discharge line from vault outside the boiler building to the WTP	Can't pump from the vault to the WTP because too much head loss to overcome. Troubleshoot and make appropriate repairs.	1	$1,000	
W23	Well field water supply piping	Replace al 1-inch diameter PVC water supply piping. This froze and split.	1	$2,000	
W24	Insulate and steam trace extracted water lines from well field to WTP	Design and install a system to insulate and steam trace the extracted water lines to prevent solidification and plugging by naphthalene and other consitiuents in the piping.	1	$75,000	Wrap small steam tracing line around water pipe in a spiral and insulate.
W25	Blow down piping from swale to WTP	Add piping to convey boiler blow down water from the boiler building to the WTP.	2	$10,000	
W26	Water softener discharge piping from swale ot WTP	Add piping to convey water softener waste water from the boiler building to the WTP.	2	$10,000	
		Subtotal		**$673,500**	
Water Treatment Plant					
T1	WTP modifications	Construct awater treatment modifications that would be needed for resumed pilot operation.	1	$200,000	Additional capacity will likely be needed for oil/water separation, carbon absorption, and possibly filtration. This is in addition to the new WTP planned for construction in 2004/2005.
		Subttotal		**$200,000**	
Instrumentation					

Table 1 - Wyckoff Steam Pilot Minimum Re-Start Action List **Status Date : 04.26.04**

ITEM #	DEFIICIENCY	DESCRIPTION AND CORRECTION REQUIRED	PRIORITY	ORDER OF MAGNITUDE COST	COMMENTS
I1	Re-install well field temperature instrumentation	Find all instrumentation, check out, re-install, start up, and calibrate.	1	$10,000	The thermocouple and fiber optic temperature field instruments for the well field were removed by the USACE and are stored in their warehouse. These systems will need to be retrieved, re-installed, and started up, re-calibrated, etc. Assume $10,000 to accomplish this. Field trailer space will also be required to house the computers connected to this system.
I2	Evaluate/enhance well field instrumentation	Design and construct any instrumentation improvements needed to get proper temperature, and water level data	1	$10,000	The existing system seemed to work well. But assume that some minor enhancements are needed.
I3	Extraction well flow monitoring	Design and install system to measure water flows from individual extraction wells.	1	$12,500	The QED pumps have stroke counters, but these have proven to be unreliable. Assume individual ulrtasonic flow meters at $1,500 each, plus $5,000 to install and to provide power.
I4	Additional pressire indicators	Install new pressure indicators on the existing taps upstream and downstream of each extraction well vapor extraction well vapor throtling valve. Typical of 6 locations, for a total of 12 valves.	1	$10,000	These indicators were originally planned, but not installed.
I5	All instrumentation	Verify proper operation of all instrumentation. Replace that found to be deffective.	1	$20,000	Assume $5,000 allowance for defective instrumentation.
		Subtotal		**$62,500**	
		TOTAL		**$2,851,750**	

Table 2 - Wyckoff Steam Pilot Enhanced Re-Start Action List

Status Date : 04.26.2004

ITEM #	INTERIM MAINTENANCE	DESCRIPTION AND CORRECTION REQUIRED	PRIORITY	ORDER OF MAGNITUDE COST	COMMENTS
Operation					
O1	Develop revised process operating parameters.	Cover operational guidelines for all systems. Reevaluate the amount of compressed air available for the extraction pumps, available biological treatment capacity, needed additional GAC system capacity, steam volume, vacuum system capacity, projected volume of extracted groundwater, etc.	1	$50,000	
O2	Prepare new detailed steam pilot operations plan	Cover operational guidelines for all systems based on changes made to the original steam pilot systems.	1	$50,000	
O3	Interim maintenance	Prepare and execute interim preventative maintenance plan for valves, pumps, painting exposed metals, etc.	2	$50,000	
		Subtotal		**$150,000**	
Steam Generation and Injection					
S1	Boiler control	Correct the boiler PLC control issues.	1	$50,000	Review and correct PLC programming.
S2	Boiler burner control	Purchase, install, and test new "industry standard" burner control system.	1	$150,000	Current system does not run reliably and is high maintenance. If this is ultimately repaired under warranty, there would be no cost for the repairs.
S3	Deaeration tank flow meter	There is no reliable way to measure the amount of water going into the deaeration tank. Design and install an appropriate flow meter scheme.	2	$2,000	Simple, direct read meter.
S4	Pilot area steam isolation valve	Install a new 6-inch isolation valve on the steam line to the pilot area. This should be downstream of the tee that goes to the DA tank.	2	$5,000	This will allow proper heating of the water in the DA tank prior to sending steam to the pilot area.
S5	Boiler startup bypass line	Provide a 1-inch diameter bypass line with 1-inch diameter shutoff valve around the existing main steam shutoff valve. Make upstream connect between the existing steam check valve and the main shutoff valve.	2	$1,000	This will allow a slow startup of the boiler, which will result in less stress to the boiler and related equipment.
S6	Boiler building air quality	Provide an HVAC system to reduce potential for odors in boiler building.	2	$50,000	This is a health and safety issue.
S7	Sour gas line to boiler	Isolate the sour gas line from boiler (this will not be used.)	1	$1,000	Will require some minor piping modifications.
S8	Additional steam injection locations	Add steam injection wells to provide more even heating.	2	$200,000	An allowance is included for this item, but the actual cost cannot be determined until the number and location of the new steam injection points are determined. It is assumed that these steam injection points can be installed with a geoprobe. This includes the cost of 10 new steam injection wells to inject steam above the aquitard. It also includes the cost of the new steam supply piping.
S9	Provisions for heating the aquitard	Determine the best way to heat the aquitard by deeper steam injection. (An alternative would be some form of resistance heating.) Design and construct chosen solution.	2	$500,000	An allowance is included for this item, but the actual cost cannot be determined until the design for aquitard heating is developed. This allowance includes the cost of 10 new steam injection wells to be screened below the aquitard. It also includes the cost of the new steam supply piping.
S10	Atomizing air compressor sheaves	Replace existing sheaves with larger set.	3	$500	Parts on hand. Very low cost.
S11	Deaerator tank coating	Remove tank, sandblast interior, apply 3-coat baked phenalic coating and reinstall.	1	$50,000	If this is ultimately done under warranty, there would be no cost for the repairs.
S12	Boiler water system cutoff switch	Add low pressure cutoff switch to water supply pumps for process water.	1	$6,000	Design is in process.
S13	Provide personnel access to top of boiler	Need access to operate stop check valves, root valve, and safety valves.	2	$20,000	
S14	Relocate root valve chain operator	The current configuration causes the chain to drag on the top and side of the boiler. Modify so that the chain runs freely.	2	$2,500	Can be operated now, but it is difficult and can wear the paint on the boiler shell.
S15	Boiler building insulation	Repair insulation that has pulled away from the roof and walls	1	$0	Should be done under warranty
S16	Steam end of the line muffler	Install a new muffler on the end of the steam bypass line	3	$5,000	
S17	Steam delivery piping supports	The supports and expansion joint for the steam piping do not allow adequate movement of the steam header as it expands and contracts with thermal changes. Re-design and reconstruct entire support amd expansion joint system.	2	$40,000	An allowance is included for this item, but the actual cost cannot be determined until the design for the support system is developed.
S18	Steam delivery piping taps	Taps were made by welding threaded nipples into steam piping. Replace all of these with appropriate half couplings welded into pipe.	2	$8,000	
S19	Boiler building work bench	Provide suitable work bench and cabinets in the boiler building for mechanical repairs	3	$1,000	
		Subtotal		**$1,092,000**	

Table 2 - Wyckoff Steam Pilot Enhanced Re-Start Action List

Status Date : **04.26.2004**

ITEM #	INTERIM MAINTENANCE	DESCRIPTION AND CORRECTION REQUIRED	PRIORITY	ORDER OF MAGNITUDE COST	COMMENTS
Vapor Extraction System					
V1	New direct contact cooler	Design and construct new, direct contact vapor cooler and associated piping for chilled water, vapor, and condensed vapors.	1	$200,000	Direct cooling of vapor off well field.
V2	New oil-water separator	Design and construct a new oil water separator for the condensed vapors, with associated piping.	1	$120,000	
V3	New recovered product pumps	Design and construct two new recovered product pumps to convey product from the vapor system oil/water separator to the product tank.	1	$20,000	
V4	New recirculating cooling water pumps	Provide two new pumps and associated piping.	1	$20,000	
V5	Reconfigure existing shell and tube heat exchanger	Reconfigure piping to existing shell and tube heat exchanger to cool the water for the new direct contact cooler.	1	$10,000	
V6	New cooling tower and enclosure	Design and construct a new cooling tower, associated pumps and enclosure.	1	$165,000	This cools water for the extracted water heat exchangers and for the direct contact cooler heat exchanger.
V7	New duct heaters	Design and construct two new duct heaters between direct contact cooler and vacuum pumps	1	$40,000	Required to keep the naphthalene in the vapor phase so that it does not clog vacuum pumps. Assume $40,000, including electrical costs .
V8	New miscellaneous electrical allowance	Allowance for electrical work associated with the new process equipment.	1	$80,250	Assume 15% of equipment cost
V9	New miscellaneous instrumentation and controls allowance	Allowance for instrumentation and control work associated with the new process equipment.	1	$80,250	Assume 15% of equipment cost
V10	New miscellaneous mechanical allowance	Allowance for mechanical work associated with the new process equipment.	1	$80,250	Assume 15% of equipment cost
V11	Rebuild vacuum pump	Change seal materials on one pump - test and re-start	1	$500	
V12	New vacuum pump	Provide new larger vacuum pump to be sure that there is enough vacuum capacity. Would require re-sizing some of the vapor collection piping.	1	$40,000	One pump has already been repaired.
V13	Thermox system capacity	Design and construct new Thermox unit of sufficient throughput and suitable for destruction of anticipated vapor contaminent concentrations.	1	$300,000	Need more capacity and existing thermox is not designed to be run at temperatures high enough to assure destruction of Dioxin. Assume installation of completely new unit. Assume 1,200 ACFM capacity.
V14	Horizontal vapor collection piping in pilot area	(1) Re-connect piping where it was cut for inspection by welding on new flanges. (2) Add steam injection at end of vapor collection pipes.	1	$10,000	(1) Welding can be done by OMI. Get test plug, fill with water, weld flanges, etc. - assume $2,000 (2) To be done by a contractor - assume $8,000
V15	Remove existing vapor knock out tank, piping and pumps.	Replaced by the new direct contact cooler.	1	$3,000	
V16	Vapor line flow meter between knock out tank and vacuum pumps	Currently have a 6-inch meter in an 8-inch line. Install a properly-sized flow meter.	2	$2,500	
V17	Vacuum pump rubber hoses	If possible, change the vacuum pump rubber hoses to a Viton hose. If not practical, obtain one complete set of replacement hoses for each pump.	2	$1,000	
V18	Vacuum pump No. 1 mechanical seals	Change the mechanical seals on LRVP 1 to Viton. (This has already been done on LRVP2.)	1	$1,000	
V19	Vacuum pump discharge piping	Re-work discharge piping on both vacuum pumps to allow changing the separator cartridges without disconnecting the entire vertical piping leg.	3	$2,500	
V20	Seal pilot area vapor cap penetrations	Perform vacuum test on pilot area. Design and construct cap penetration and edge seals.	2	$150,000	Boot all penetrations, place concrete seal along sheet pile wall.
V21	Insulate and steam trace extracted vapor lines.	Design and install a system to heat the extracted vapor lines to prevent solidification and plugging by naphthalene and other consitiuents in the piping.	1	$75,000	Wrap small steam tracing line around vapor pipe in a spiral and insulate.
V23	Prepare and execute a comprehensive approach to air emissions	Cover air emissions from the boiler, Thermox unit, open tanks, and other sources. Include monitoring type and schedule, agency coordination, and reporting.	1	$75,000	
		Subtotal		**$1,476,250**	
Water Extraction System					
W1	Extraction well pump test	Develop well pump test plan and perform pump test to determine the capacity of the pilot area groundwater flow.	2	$45,000	

Table 2 - Wyckoff Steam Pilot Enhanced Re-Start Action List

Status Date : 04.26.2004

ITEM #	INTERIM MAINTENANCE	DESCRIPTION AND CORRECTION REQUIRED	PRIORITY	ORDER OF MAGNITUDE COST	COMMENTS
W2	Unplug and re-develop all extraction wells	Inject steam to dissolve the naphthalene, use standard well development techniques to re-develop the gravel pack, and remove sediment in the bottom of the wells.	1	$100,000	This work should be completed prior to the vacuum test. EW01 is plugged solid.
W3	Extraction well cap modifications	Modify well caps to provide penetrations for slurper pumps and for steam injection.	1	$21,000	Assume 7 caps at $3000 each.
W4	Steam injection lines in the extraction wells	Design and install steam lines to remove naphthalene plugging.	1	$25,000	Requires running steam lines to each extraction well.
W5	Extraction well slurper pumps	Design and install piping in the extraction wells to provide backup slurper pump capability.	2	$35,000	Slurper pump will provide a backup in case the QED pump fails, will provide an adjustible intake for NAPL removal and will add capacity to QED pumps.
W6	Lower the groundwater extraction pumps.	Set the pumps so that they are as close to the bottom of the well as possible.	1	$40,000	Will require new air supply and discharge hoses. Assume will use QED materials.
W7	Extraction pump air supply capacity.	Add air supply capacity to the extraction well pumps. Either increase the size of the air supply piping, add air receivers in the pilot area, or a combination,	1	$10,000	Needed for proper operation of the pumps.
W8	New oil-water separator	Design and construct a new oil water separator for the extracted groundwater, with associated piping.	1	$120,000	Install this oil/water separator before the extracted groundwater heat exchangers.
W9	New recovered product pumps	Design and construct two new recovered product pumps to convey product from the groundwater oil/water separator to the product tank.	1	$20,000	
W10	New extracted groundwater heat exchangers	Provide two new shell and tube heat exchangers for the extracted groundwater. One will be in service while the second is being cleaned. Include a system for handling the wastes that collect in the heat exchangers.	1	$80,000	
W11	Old liquid/liquid heat exchangers	Remove the old heat exchangers.	1	$5,000	
W12	Extracted groundwater flow meter	The current flow meter have never worked correctly and is susceptible to naphthalene plugging. Purchase and install a new magnetic flow meter.	1	$7,500	
W13	Water Level Measurement	Evaluate current water level measurement system. Additional reference transducers will be required to correct for system vacuum impacts.	1	$15,000	
W14	TOC analyzer	Move analyzer to appropriate WTP location. Purchase and install new analyzer that is appropriate for measurement of constituents in liquid from boiler building to WTP after product separation.	1	$10,000	
W15	Extracted water piping in pilot area	Repair damaged flexible bellows in 2 places.	1	$5,000	
W16	Extracted water piping and drains	Slope piping to drain. Replace all extracted water piping drain valves and un-clog vertical drain piping. Add drains in all low spots. Design and construct a system to blow out the water with compressed air or to otherwise drain the extracted water piping when not in service to prevent damage during freezing weather.	1	$10,000	The current piping cannot be drained in freezing weather. Some drain legs have frozen and split. Others are clogged with product. Consider a different way to drain the pipe, since the drains rapidly clog.
W17	Replace check valves on extraction well discharges	Replace some - probably about half - of the 1-1/2" diameter check valves on extraction well discharge piping.	1	$2,000	These are clogged with product.
W18	Replace isolation valves on extraction well discharges	Replace all of the 1-1/2" diameter isolation valves on extraction well discharge piping.	1	$3,000	These are clogged with product. (??)
W19	New recovered product pumps	Design and construct two new recovered product pumps to convey product from the recovered liquid oil/water separator to the product tank.	1	$10,000	
W20	Gate and globe valves on steam supply lines in the field	Check, maintain and replace as needed	1	$1,000	
W21	Product pump overload protection	Change from electronic to mechanical overload protection.	2	$1,000	Electronic system is too sensitive and results in frequent nuisance tripping of the pumps.
W22	Discharge line from vault outside the boiler building to the WTP	Can't pump from the vault to the WTP because too much head loss to overcome. Troubleshoot and make appropriate repairs.	1	$1,000	
W23	Well field water supply piping	Replace al 1-inch diameter PVC water supply piping. This froze and split.	1	$2,000	
W24	Insulate and steam trace extracted water lines from well field to WTP	Design and install a system to insulate and steam trace the extracted water lines to prevent solidification and plugging by naphthalene and other consitiuents in the piping.	1	$75,000	Wrap small steam tracing line around water pipe in a spiral and insulate.
W25	Blow down piping from swale to WTP	Add piping to convey boiler blow down water from the boiler building to the WTP.	2	$10,000	

Table 2 - Wyckoff Steam Pilot Enhanced Re-Start Action List

Status Date : **04.26.2004**

ITEM #	INTERIM MAINTENANCE	DESCRIPTION AND CORRECTION REQUIRED	PRIORITY	ORDER OF MAGNITUDE COST	COMMENTS
W26	Water softener discharge piping from swale ot WTP	Add piping to convey water softener waste water from the boiler building to the WTP.	2	$10,000	
W27	New south extraction wells	Design and construct eight new extraction wells at the south edge of the site. Half of these wells would extend below the aquitard and half would be completed just above.	1	$78,000	The purpose of these wells is to recover any product that would be pushed by the steam towards the south.
W28	New south extraction well pumps	Design and construct eight new extraction well pumps and discharge piping.	1	$120,000	
W29	New south steam pilot area south sheet pile wall	Install a new sheetpile wall along the south edge of the pilot area - extending ten feet below the bottom of the aquitard.	1	$300,000	The purpose of this wall is to block the migration of comtaminates towards the south - either above or below the aquitard.
		Subtotal		**$1,161,500**	
Water Treatment Plant					
T1	WTP modifications	Construct awater treatment modifications that would be needed for resumed pilot operation.	1	$200,000	Additional capacity will likely be needed for oil/water separation, carbon absorption, and possibly filtration. This is in addition to the new WTP planned for construction in 2004/2005.
		Subttotal		**$200,000**	
Instrumentation					
I1	Re-install well field temperature instrumentation	Find all instrumentation, check out, re-install, start up, and calibrate.	1	$10,000	The thermocouple and fiber optic temperature field instruments for the well field were removed by the USACE and are stored in their warehouse. These systems will need to be retrieved, re-installed, and started up, re-calibrated, etc. Assume $10,000 to accomplish this. Field trailer space will also be required to house the computers connected to this system.
I2	Evaluate/enhance well field instrumentation	Design and construct any instrumentation improvements needed to get proper temperature, and water level data	1	$10,000	The existing system seemed to work well. But assume that some minor enhancements are needed.
I3	Extraction well flow monitoring	Design and install system to measure water flows from individual extraction wells.	1	$12,500	The QED pumps have stroke counters, but these have proven to be unreliable. Assume individual ulrtasonic flow meters at $1,500 each, plus $5,000 to install and to provide power.
I4	Additional pressire indicators	Install new pressure indicators on the existing taps upstream and downstream of each extraction well vapor extraction well vapor throtling valve. Typical of 6 locations, for a total of 12 valves.	1	$10,000	These indicators were originally planned, but not installed.
I5	Add temperature and water pressure instrumentation for lower aquifer	Design and construct instrumentation improvements needed to get proper temperature, and water level data from below the aquitard.	1	$550,000	Assume a fiber optic system comparable to the one used for the upper aquifer without transducers. GeoProbe cannot be used to install in lower aquifer.
I6	All instrumentation	Verify proper operation of all instrumentation. Replace that found to be deffective.	1	$20,000	Assume $5,000 allowance for defective instrumentation.
		Subtotal		**$612,500**	
		TOTAL		**$4,692,250**	

Table 3 - Wyckoff Thermal Remediation Cost Worksheet

Status Date: 04.26.04

DESCRIPTION	ESTIMATED COST		ASSUMPTIONS/NOTES
(1) Cost Summary			
	Minimal Pilot	**Enhanced Pilot**	
Capital Cost	$2,851,750	$4,692,250	$1,840,500
Operations and Engineering Cost	$8,271,220	$8,737,420	$466,200
TOTAL	**$11,122,970**	**$13,429,670**	$2,306,700
(2) Cost Detail			
(a) Capital Cost			
From Table 1	$2,851,750	$4,692,250	
(b) Operating Costs			
Ongoing Treatment Plant and Steam Plant O&M Monthly Costs			
Steam pilot operation	$120,000	$120,000	Assume 6 boiler operators at $20,000 per month each
Increased WTP operation	$15,000	$15,000	Assume 1 additional operator needed at $15,000 per month
Utility and Fuel Monthly Costs			
Diesel for boiler	$18,000	$30,000	Assume average of 15K gallons per month times $1.20 for minimal and average of 25K gallons for enhanced
Propane for thermox	$9,300	$13,950	Assume average of 6,200 gallons per month times $1.50 per gallon for minimal and average of 9,300 for enhanced.
Electric power	$6,000	$6,000	Assume average electricity cost of $6,000 per month, based on past pilot
Total Monthly Operating Costs	$168,300	$184,950	
Operating cost for 28 months of Active Steaming	$4,712,400	$5,178,600	
Operating cost for 12 months of cool down and monitoring	$300,000	$300,000	Assume keep 1 boiler operator and $5,000 per month expenses to keep boiler running at a low level.
Total Estimated Operating Cost	$5,012,400	$5,478,600	
Waste Disposal Total Costs			
Carbon Reactivation	$768,000	$768,000	Assume 16,000 pounds/month at $1.20 per pound times 40 months
Recovered liquid product	$250,000	$250,000	Assume additional 100,000 gallons times $2.50/gallon
Solid product wastes	$83,820	$83,820	Assume 63 pounds per day X 1,200 days X $1.10 per pound disposal cost for miscellaneous drummed solids. Assume no solid naphthalene will be generated by the process.
PPE	$32,000	$32,000	Assume an average of 4 drums per month times 40 months @$200 per drum
Total Waste Disposal Costs	$1,133,820	$1,133,820	
Total Estimated Operation and Waste Disposal Costs	$6,146,220	$6,612,420	
(c) Engineering and Data Management Costs			
Engineering support and coordination during pilot	$37,500	$37,500	Assume 1-1/2 FTE engineers at $25,000 per month each averaged over life of pilot
Field data collection , database management and reporting	$20,000	$20,000	Assume 1 data specialist at $18,000 per month, plus $2,000 in other labor
Groundwater sampling	$4,000	$4,000	Assume quarterly sampling events at $12,000 each
Lab analysis and reporting	$1,000	$1,000	Assume quarterly sampling events at $3,000 each
Total Monthly Engineering and Data Management Costs	$62,500	$62,500	
Engineering cost for 28 months of Active Steaming	$1,750,000	$1,750,000	
Engineering cost for 12 months of cool down and monitoring	$375,000	$375,000	Assume monthly cost is 1/2 of active steaming period cost
Total Estimated Engineering and Data Management Cost	$2,125,000	$2,125,000	
Total Operations and Engineering Costs	$8,271,220	$8,737,420	

Reference Material

Attachment 1

Pilot Study Extraction Well/Vapor Recovery Video Results and NAPL Recovery Recommendations

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DATE: September 25, 2003

Introduction

The U.S. Army Corps of Engineers designed and installed an in situ thermal treatment pilot study to evaluate the effectiveness of steam injection technology at the Wyckoff site. Seven extraction wells and horizontal vapor recovery piping (HVRP) were installed in the pilot study area. Extraction well yields and vapor recovery system performance during initial pilot study operations have decreased over time. The nature of the well and vapor system clogging or fouling was not understood. To develop rehabilitation recommendations, a video inspection of the wells and HVRP system was recommended to assist in identifying the cause of the impaired performance. The approach to the video inspection work is outlined in the work plan (see Attachment A).

This technical memorandum summarizes the video inspection results for three HVRP lines and five extraction wells. Equipment and operation recommendations by the pilot study team to optimize nonaqueous-phase liquid (NAPL) recovery following steam injection startup also are summarized.

Vapor Collection Video Results

Three HVRPs (HV-4, HV-5, and HV-6) were inspected using video equipment on July 31, 2003. All HVRP lines inspected had some level of encrustation accumulation. The encrustation material appears to be naphthalene crystals that precipitated from the vapor phase in the areas where lower temperatures occurred in the piping system. Inspection results indicate that HV-6 had the least amount of visible encrustation in the piping and HV-4 appeared to have the most. Portions of line HV-4 were completely plugged with naphthalene crystals and could not be inspected with the video equipment. Detailed HVRP inspection information and photographs are presented in Attachment B.

Extraction Well Video Results

A video inspection of five extraction wells in the pilot study area was performed on August 11, 2003. Inspections were performed on extraction wells E02, E03, E04, E05, and E07. Video inspection was not performed on extraction wells E01 and E06. Well E06 was intentionally left operational to maintain hydraulic control and the pump in well E01 could not be removed before the inspection. The purpose of the inspections was (1) to assess well screen condition; (2) to identify corrosion, encrustation, or other conditions that may be responsible for reduced well yields; and (3) to determine the need for well rehabilitation.

In general, the well screens appear to be in good condition with limited evidence of blockage. Naphthalene crystals primarily were observed inside the well casing above ground surface. The most prominent material observed was product globules (creosote or related chemicals) located in many of the screen openings as well as evidence of product smearing on the screens. In some wells (for example, E04), significant quantities of sediment had accumulated in the bottom of the well. Naphthalene crystals and dense NAPL (DNAPL) also were present in some of the sumps, the crystals likely originated from the upper portion of the well casing and settled down into the sumps.

Well redevelopment is recommended before re-installing the extraction pumps. The sediment and naphthalene material in the well sumps should be cleaned out as the first step in well development. After sump cleaning is completed, a surging process should be used to clean the well screens using a brush, swab, surge block, or a combination of equipment. A more detailed discussion of the well video inspection results is presented in Attachment C.

NAPL Removal Recommendations

A telephone conference was conducted on September 3, 2003, by the pilot study team. Topics discussed included: (1) methods to optimize NAPL recovery during the continuation of the steam pilot study at the Wyckoff site; (2) extraction well monitoring; and (3) recommendations for placement and operation of extraction well pumps until the steam pilot study is resumed. The meeting summary notes are presented in Attachment D. The conclusions and recommendations developed during the conference call are summarized below.

Fluid Removal

The preferred fluid recovery system in each extraction well consists of a two-pump system. One QED Hammerhead pump with the pump intake set at the bottom of the well screen and one Slurper pump removing fluid from the top of the fluid column with an adjustable inlet elevation. The following are benefits of the two-pump approach:

- Improved ability to remove both light NAPL (LNAPL) and DNAPL

- Redundant pumping capability
- More pumping capacity to respond to initial water removal requirements during steam injection startup
- QED pumps are onsite and ready for use, and the Slurper pump equipment is inexpensive.
- QED pump intake elevation settings will not have to be adjusted during the pilot study. This alleviates the safety concerns associated with adjusting the QED pump settings.

Several actions that should be completed before installing the two-pump extraction systems were identified and are listed in Attachment D.

Monitoring

From an operational standpoint (total fluids recovery), there does not appear to be a need to collect discrete NAPL layer thickness measurements during the pilot study. The total fluid level in the extraction wells can be monitored using the calibrated pressure transducer currently installed in each well and a measurement of the well vacuum pressure. Total extraction system discharge volumes should be recorded noting the presence of LNAPL and DNAPL discharged from each extraction well.

Interim Hydraulic Control Measures in Pilot Study Area

During the period until the pilot study is restarted, some hydraulic control pumping will be required to manage vertical hydraulic gradients in the pilot study area during the winter rainy season. The objective is to manage the shallow aquifer heads in order to maintain an upward vertical hydraulic gradient across the underlying aquitard. This will reduce the possibility of dissolved and NAPL contaminant migration through the aquitard. The number of wells and initial pumping rate(s) required to accomplish this objective should be confirmed using the groundwater flow model currently being developed.

Attachment A

Work Plan
Well Video Inspection
Wyckoff/Eagle Harbor Superfund Site
Bainbridge Island, Washington

Introduction

The US Environmental Protection Agency (USEPA) has selected in-situ thermal treatment technology to pilot test as a possible subsurface remedy for soil and groundwater contamination related to historic wood treatment operations at the Wyckoff site. The US Army Corps of Engineers (USACOE) designed and installed a pilot testing system to evaluate the effectiveness of steam injection technology at the site. Seven extraction wells and horizontal vapor recovery piping (HVRP) were installed in the pilot. Extraction well yields and vapor recovery system performance during initial pilot test operations have decreased over time and, in the case of the extraction wells, currently do not yield sufficient quantities of water to effectively test the technology. The nature of the well and vapor system clogging or fouling has not been determined. In order to develop well rehabilitation recommendations, a well video inspection task was recommended to assist in identifying the cause of the impaired well yield.

This work plan presents a description of the video inspection task. Six of the seven extraction wells and two HVRP systems will be inspected. Well E6 will continue to operate and maintain groundwater levels during implementation of this task. This work will be completed under work assignment WA#107-TA-TA-10W2. The video equipment will be supplied and operated by SCS, Inc personnel. All field work activities associated with this task will be supervised by SCS personnel. A CH2M HILL hydrogeologist will be present to observe and document video results. Health and Safety protocols described in the USACOE RAMP must be observed at all times during the implementation of this work plan. Additionally, all CH2M HILL personnel will comply with the CH2M HILL Site Safety Plan. The work will be performed per the attached schedule.

Approach

Six extraction wells will be inspected using downhole camera equipment; the camera will have both downward and side view capability. Five 10-inch diameter extraction wells (E1, E2, E3, E4, and E5) and one 6-inch diameter extraction well (E7) will be inspected to total depth. Well E6 will continue to operate and will not be inspected at this time. Two horizontal vapor recovery pipes will also be inspected. These horizontal vapor wells do not have name designations; well designations will be assigned during the video inspection.

The video inspection will be recorded on VHS tapes. All Extraction well construction logs (E1, E2, E3, E4, E5, E6, and E7) are attached.

This approach discussion is divided into three tasks: well preparation, video inspection, and equipment cleanup. The activities associated with these tasks are described below

Well Preparation

- Disassemble wellhead and remove pump equipment. Upon removal, inspect pump and pump column for signs of encrustation or fouling. Photograph pump assembly components and note if signs of abnormal wear, corrosion, mineral encrustation, or biofilm are present. Collect samples of encrustation or biofouling material from the pump assembly and place into 40 ml VOA sample bottles.

- Measure: 1) depth to fluid and the LNAPL and DNAPL layer thickness using an interface probe, and 2) the total depth of the well with a weighted tape. Compare measured total well depth to as-built depth to estimate the thickness of the sediment layer present in the well sump.

- Compare the thickness of product (NAPL layers) within the screen zone to the length of the well screen. If the thickness of product extends over 25% or more of the screen length, product will be removed from the well prior to inspection. The goal is to inspect at least 75% of the saturated portion of the well screen and video inspection cannot be performed in the portions of the well screen containing product. Product will be removed from extraction wells by OMI personnel using existing onsite equipment.

- Allow the well to stabilize prior to inspection. Typically, pump removal activities disturb fine sediment present in the well resulting in an increase in suspended solids in the water column. The suspended solids cloud the water reducing the clarity and effectiveness of the video inspection. To improve video quality below the water table, some equilibration time will be required following pump removal to allow turbidity in the water column to settle. The duration of this equilibration period is dependent on the grain size of the suspended material (i.e., finer material requires longer settlement times). Ideally, the wells should be allowed to settle for four to five days following pump or product removal.

Video Inspection

Due to the likely presence of LNAPL in the extraction wells, video inspection of the saturated and unsaturated portions of each well must be performed separately. Advancing the downhole camera through the LNAPL would smear the camera lens and degrade picture quality. Therefore, inserting the camera below the LNAPL layer without exposing it to the product is necessary to inspect the saturated portion of the wells. A camera insertion conduit will be installed in each well prior to inspecting the saturated portion of the well screen. This approach is described below.

- Perform a video inspection of the unsaturated portion of well. The inspection will focus on the condition of the well casing joints and the unsaturated portion of the well screen. In addition, the video inspection will confirm well construction details (e.g. depth to top of well screen). Due to the likely presence of an LNAPL layer at the top of the water column, the video camera should not penetrate the fluid level in the well. The field task supervisor may conclude that it would be more efficient to inspect the unsaturated portions of all six wells first, and then return to each well to inspect the saturated portions. This is an acceptable approach if careful documentation and labeling of video tapes is performed. Documentation will consist of a field log book, a well video survey form for each well, and a video tape recording of the camera inspection. The well video survey form will include well construction details observed during the inspection as well as well condition observations.

- Assemble a camera insertion conduit. The conduit will be used to insert the video camera below the LNAPL layer without smearing the camera lens. The insertion conduit will be constructed of threaded 4-inch diameter, schedule 40, PVC pipe. Confirm that the downhole camera equipment will fit inside 4-inch PVC pipe. The conduit will be of sufficient length to extend from a suitable working height above ground surface to below the LNAPL layer. The down hole end of the conduit will be sealed with an appropriately sized zip-lock bag and duct tape. Ideally, more than one conduit should be constructed and they should be installed in the extraction wells the day before conducting the video inspection. The conduit should be inserted slowly and carefully into the extraction well water column to minimize disturbance. Once the end of the conduit is positioned below the LNAPL layer, the conduit should be secured to the wellhead by means of a pipe support clamp. Using an appropriate length of smaller diameter PVC pipe, gently break the conduit bottom seal (i.e., punch a hole in the zip-lock bag). The video camera equipment can then be inserted into the conduit and lowered into the water column.

- Perform a video inspection of the saturated portion of the well. The inspection will focus on the condition of the well screen and identify the presence of clogging and/or fouling material. In addition, confirm well construction details. Avoid advancing the video camera lens into a DNAPL layer at the bottom of the well. If clogging and/or fouling material is identified in the saturated portion of the screen zone, detailed descriptions of the thickness and depth interval of the material should be recorded. This information will be of assistance during possible follow-up sample collection efforts.

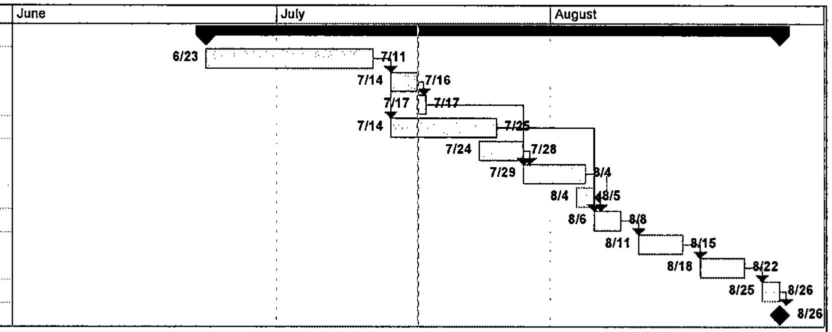
- Perform a video inspection of two of the HVRP systems. One system will be located near the sheet pile wall at the North end and the second will be located near the interior of the site. OMI personnel will access the HVRP systems by removing the flange at the 1 ¼ inch flanged globe valve. A sewer camera of suitable diameter will be used to video the HVRP systems.

Equipment Cleanup

- Following the camera manufacturer's recommendations, clean the video camera lens assembly prior to each well inspection. Camera body, wiring, and cable should be cleaned as necessary for safe operation. The site decon pad and steam cleaning equipment are available for cleaning bulky components.

- Investigation derived waste (IDW) will consist primarily of personal protection equipment (PPE). All IDW will be disposed of per existing site protocols.

ID		Task Name	Duration	Start	Finish	Predecessors	Resource Names
1		**Video Wells**	**47 days**	**Mon 6/23/03**	**Tue 8/26/03**		**Trotman,Varljen**
2		Prepare draft well video plan	15 days	Mon 6/23/03	Fri 7/11/03		Trotman
3		Review draft well video plan	3 days	Mon 7/14/03	Wed 7/16/03	2	Team
4		Finalize well video plan	1 day	Thu 7/17/03	Thu 7/17/03	3	Trotman,Varljen
5		Procure cameras	10 days	Mon 7/14/03	Fri 7/25/03	2	Varljen
6		Field survey for as-builts	3 days	Thu 7/24/03	Mon 7/28/03		CH2M HILL
7		Remove well heads and pumps / modify horiz. vapor collectors	5 days	Tue 7/29/03	Mon 8/4/03	4FS+3 days,6	Leeper
8		Remove LNAPL and DNAPL	2 days	Mon 8/4/03	Tue 8/5/03	7FF+1 day	Leeper
9		Take videos	3 days	Wed 8/6/03	Fri 8/8/03	5,8	Trotman,Varljen
10		Analyze images & prepare well video report	5 days	Mon 8/11/03	Fri 8/15/03	9	Trotman,Varljen
11		Team review	5 days	Mon 8/18/03	Fri 8/22/03	10	Team
12		Finalize well video report	2 days	Mon 8/25/03	Tue 8/26/03	11	Trotman,Varljen
13		Issue Well Photo Deliverable	0 days	Tue 8/26/03	Tue 8/26/03	12	Trotman,Varljen



Project: Wykoff_09ul03_video
Date: Thu 7/17/03

Task		Milestone		Rolled Up Critical Task		Split		Group By Summary	
Critical Task		Summary		Rolled Up Milestone		External Tasks			
Progress		Rolled Up Task		Rolled Up Progress		Project Summary			

R052029

Holt Drilling INC. 11865

WELL COMPLETION REPORT Tag# AGN 546

25-2E-35A

Project WYCKOFF EXTRACTION WELL Well No. E-01

Completion date 10-1-01

Contractor Holt Drilling

Rig BE 22 W

Operator Wade

Inspector Bob Hanford

Depth 36.35 Datum CAP SURFACE

HOLE DATA

Size: ____ in. to ____ ft.
16 in. to 36.35 ft.
____ in. to ____ ft.

CASING

Type STEEL

Mfr. —

Ht. above gnd. surf. ____

Drive shoe STEEL welded.

Size: ____ in. to 40" ft.
16 in. to 36.35 ft.
____ in. to ____ ft.

SCREEN

Type V- WRAP 10"

Mfr. Johnson

Composition 304 SS Dia. 10"

Fittings:	Length	Dia.
Packer		
Riser	9	10"
Tailpipe	5	10"

FILTER

Source Colorado

Composition Silica

Gradation 10-20

Inst. method Pour from top

Volume used 76 Bags 10-20 2 20/40

Depth 32.4 to 4.5 ft.

→ 20-40 4.5-3.0

GROUT

Composition Silica cement

Volume used ~ 6 gal weight 15.1

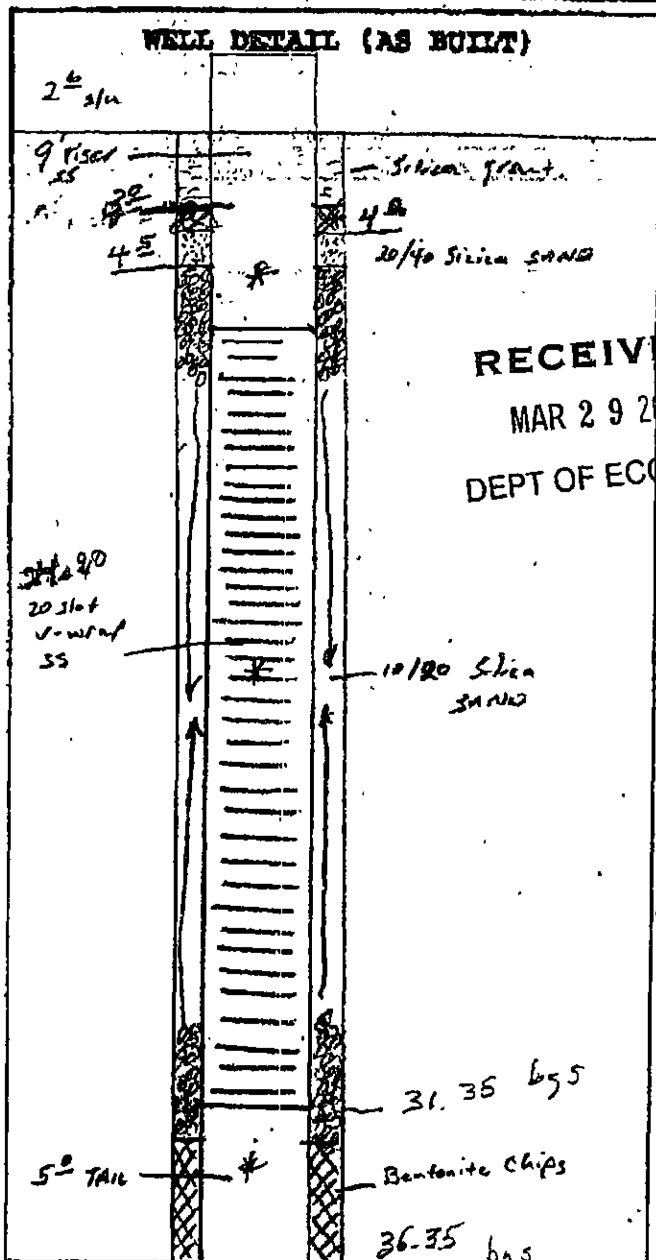
Inst. method Poured from top

Grout Depth 3 to 4 ft.

Bentonite chips 32.4 to 36.35 ft.

3 bags chips

REMARKS: Total length 38.96.



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Holt Drilling INC. 111866

WELL COMPLETION REPORT Tag # AGN 547

25-2E35A

Project Wyckoff Extraction Well Well No. E-02

Completion date 9-28-01 → 10-1-01
Contractor Holt Drilling
Rig 22W 36
Operator Wade Iverson
Inspector Bob Hanford
Depth 42.94 Datum TOC's

HOLE DATA
Size: 16 in. to 43 ft.
20 in. to ~4 ft.
in. to ft.

CASING SA-312
Type 10" SCH 40S TP-304/TP 304L ASTM A-312
Mfr. Bristol welded
Ht. above gnd. surf.
Drive shoe
Size: 16 in. to 43 ft.
in. to ft.
in. to ft.

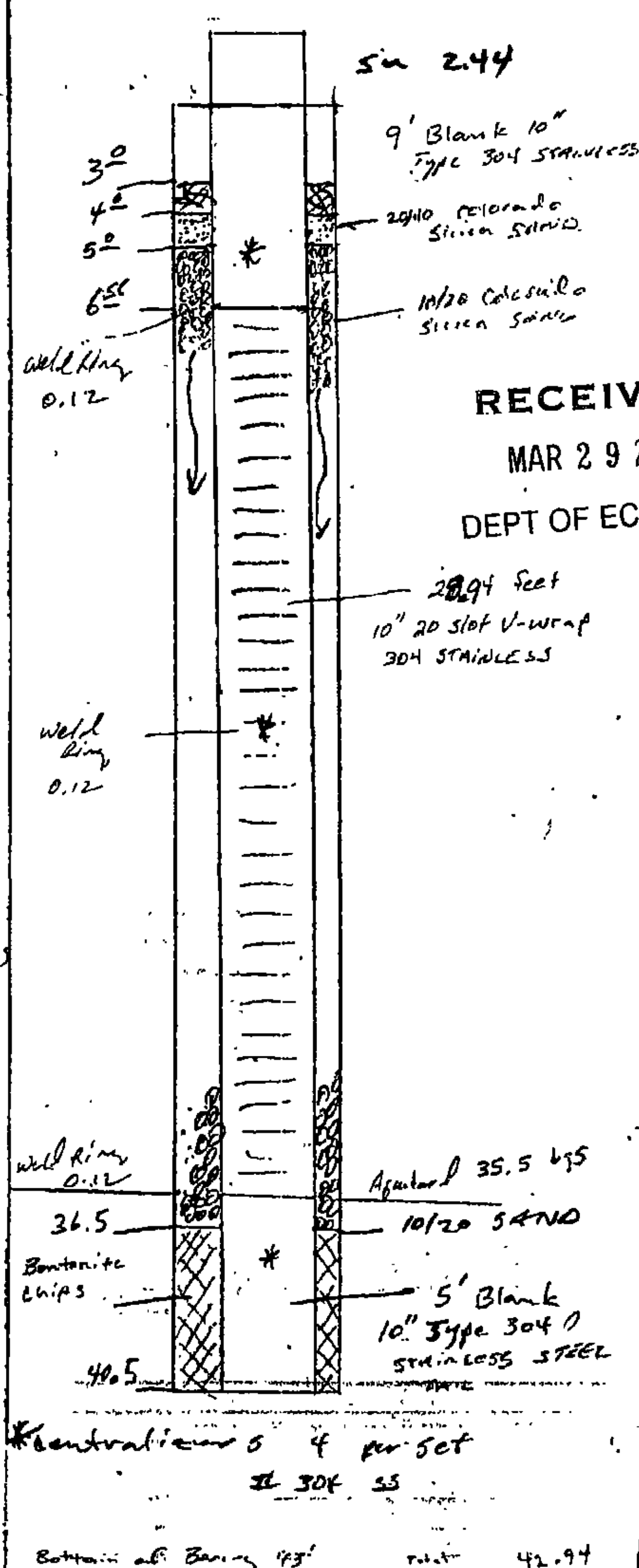
SCREEN
Type 20 slot
Mfr. Johnson
Composition 304 SS Dia. 10" ID

Fittings:	Length	Dia.
Packer	—	—
Riser	9.0	10" ID
Tailpipe	5.0	10" ID

FILTER
Source Colorado Springs Plant (Oglebay Norton)
Composition Silica SAND
Gradation 10-20 69 bags 20/40 2 bags
Inst. method Top fill
Volume used 69
Depth 36.5 to 5.0 bgs ft.

GROUT
Composition Bentonite Chips
Chips Volume used 5 bags
Inst. method Poured Through Annulus
Chips Depth 36.5 to 42.94 ft.
Silica/Cement 4.0 to 3.0 bgs ft.
6 gals weight 14.95 lb/
REMARKS:

WELL DETAIL (AS BUILT)



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Holt Drilling Inc.

WELL COMPLETION REPORT Tag # AGN548
25-2E-35A

Project Wyckoff Well No. E-03
Completion date 10-9-01
Contractor Holt Drilling
Rig STARR 71
Operator Tony
Inspector Bob Hanford
Depth 33.8 Datum bgs

HOLE DATA

Size: 20 in. to 3.5 ft.
16 in. to 33.8 ft.
in. to ft.

CASING

Type STEEL
Mfr. —
Ht. above gnd. surf.
Drive shoe STEEL welded
Size: 16 in. to 33.8 ft.
in. to ft.
in. to ft.

SCREEN

Type V-wrap 304 STAINLESS
Mfr. Johnson
Composition 304 SS Dia. 10"

Fittings:	Length	Dia.
Packer		
Riser	9.0	10"
Tailpipe	5.0	10"

FILTER

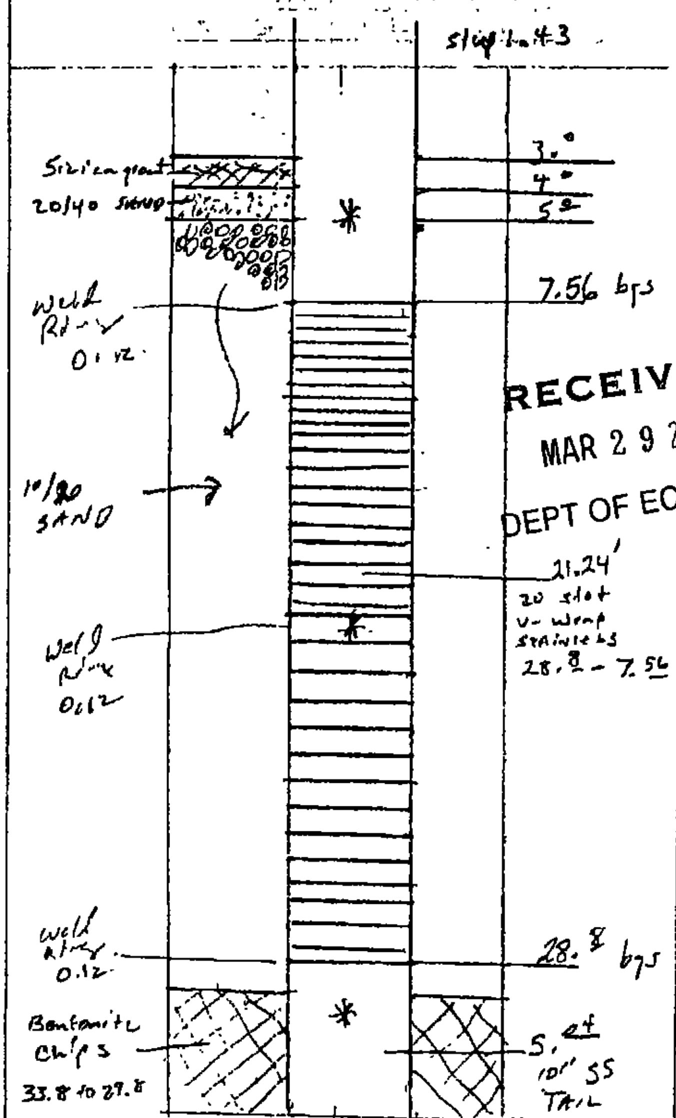
Source Colorado
Composition 10-20 Silica
Gradation 10/20 — 20/40 bags
Inst. method Poured from Top
Volume used 70 bags
Depth 29.8 to 5.0 ft.

GROUT

Composition Silica/Cement
Volume used ~5 gal. grout
Inst. method Pour from Top
Depth 3.0 to 4.0 ft.
Chips Bentonite 4 bags 33.8 to 29.8 ft.

REMARKS:

WELL DETAIL (AS BUILT)



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* centralizers 4 per set
# 304 SS

Holt Drilling Inc. 111868

R052029

Tag# AGN549

25-2E-35A

WELL COMPLETION REPORT

Project Wyckoff Extraction

Well No. E-Ø4

Completion date 10-5-01

Contractor Holt Drilling

Rig Dalled Stake 71 Install BE 22 W

Operator Miller Iverson

Inspector Bob Hanford

Depth 36.5 Bgs Datum Top of Sheet Pile approximately = 20 mllw

HOLE DATA

Size: 20 in. to ~4 ft.
16 in. to 36.5 ft.
___ in. to ___ ft.

CASING

Type STEEL

Mfr. —

Ht. above gnd. surf. —

Drive shoe

Size: 20 in. to ~4 ft.
16 in. to 36.5 ft.
___ in. to ___ ft.

SCREEN

Type 20 slot V-wrap

Mfr. Johnson

Composition ss 304 Dia. 10"

Fittings:	Length	Dia.
Packer		
Riser	9'	10"
Tailpipe	5'	10"

FILTER

Source Colorado

Composition silica

Gradation 10-20

Inst. method Poured from Top

Volume used 68 Bags 2 Bag 20/40

Depth 32.5 to 6.96 ft.

GROUT

Composition Silica grout

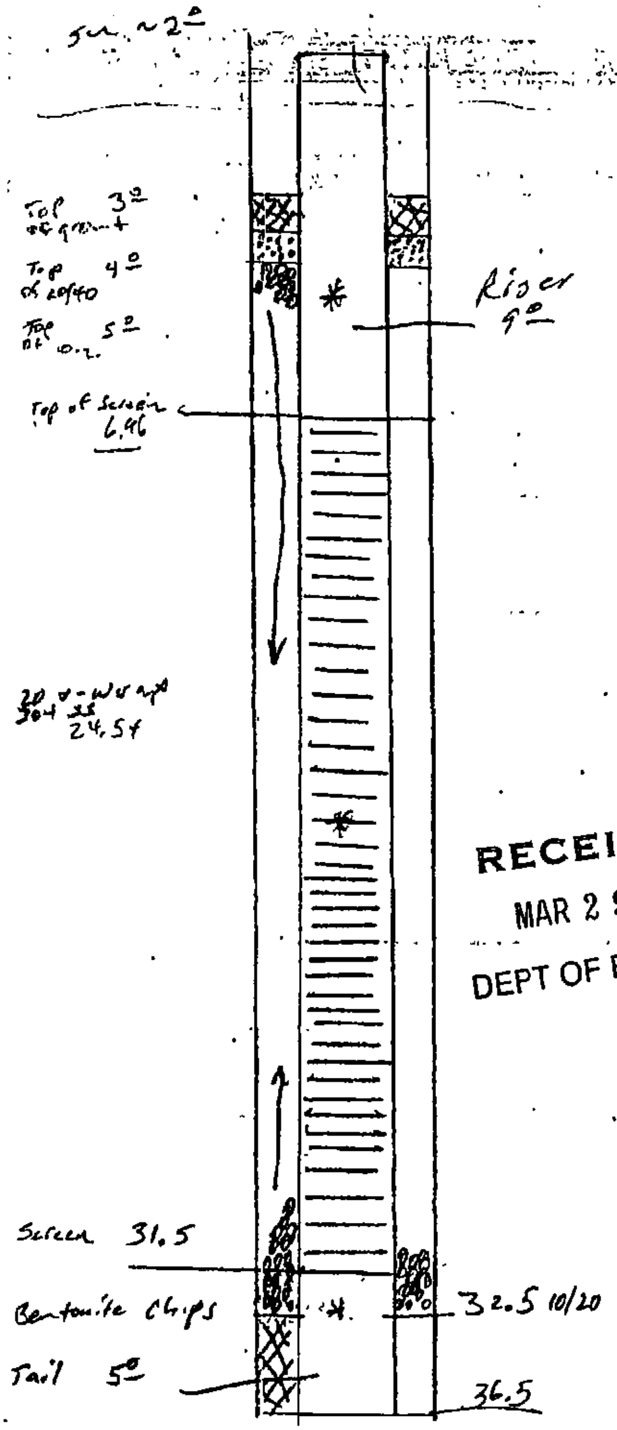
Volume used 4 bag chips - ~5 gallons grout

Inst. method Poured from top

Depth 3' to 4' ft.
chips 36.5 to 32.5 ft. bgs.

REMARKS:

WELL DETAIL (AS BUILT)



* centralizer 4 per set SS #304

Total length 38.54

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Holt Drilling Inc. 111869

R052029

Tag # AGN 550

25-2E-35A

WELL COMPLETION REPORT

Project Wyckoff Extraction Well — Well No. E05

Completion date 10-2-01
Contractor Holt Drilling
Rig BE W-22
Operator WADE
Inspector Bob Hunter
Depth 35 bgs Datum 20 ft
elevation — Sheet pile wall

HOLE DATA
Size: 20 in. to ~4' ft.
16 in. to 35 bgs ft.
in. to ft.

CASING
Type STEEL
Mfr. UK
Ht. above gnd. surf.
Drive shoe
Size: 20 in. to ~4' ft.
16 in. to 35' ft.
in. to ft.

SCREEN
Type V-wrap 20 slot
Mfr. Johnson
Composition 304 SS Dia. 10"

Fittings:	Length	Dia.
Packer	—	—
Riser	9'	10"
Tailpipe	5'	10"

FILTER
Source Colorado
Composition Silica
Gradation 10-20
Inst. method Poured from top
Volume used 72
Depth 31' to 5' ft.

GROUT
Composition Silica flower / cement
Volume used ~5 gals
Inst. method Pour from Top
Depth 3 to 4 ft.
Bentonite chips 35 to 31 ft.
4 bags Poured from Top
REMARKS:

WELL DETAIL (AS BUILT)

Total length tail screen & riser 37.04'

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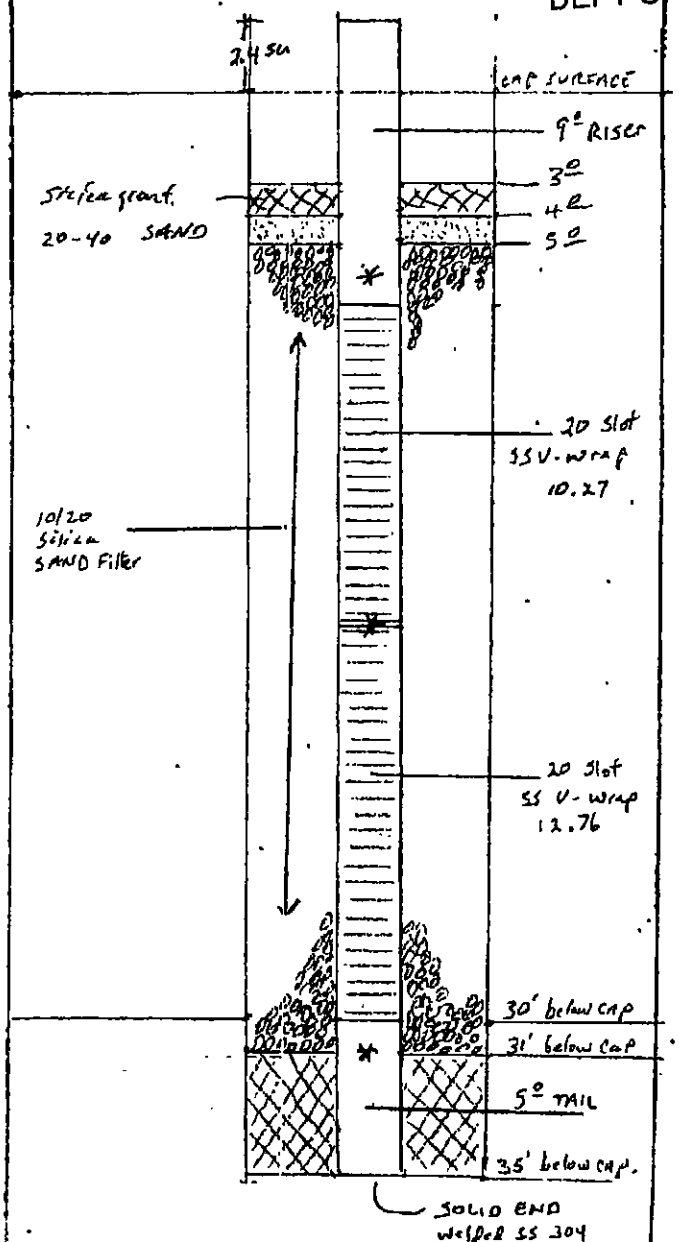


* centralizer 4 each SS 304 — Frz casing/screen 3304

Holt Drilling Inc.

111870

R052024

Tag # AGN551

25-2E-35A

WELL COMPLETION REPORT

Project Wyckoff Extraction well Well No. E-06 B

Completion date 10-4-01

Contractor Holt Drilling

Rig MARL 71 Drill / BE W-22 Gastall

Operator Richard Miller, Wade Iverson

Inspector Bob Hartmund

Depth 43' Datum 20' top of sheet pile MLLW

HOLE DATA

Size: 20 in. to ~4' ft.
16 in. to 43' ft.
in. to ft.

CASING

Type 304 STAINLESS

Mfr.

Ht. above gnd. surf. 1.5

Drive shoe

Size: in. to ft.
16 in. to 43' ft.
in. to ft.

SCREEN

Type V-wrap 20 slot

Mfr. Johnson

Composition 304 SS Dia. 10

Fittings:	Length	Dia.
Packer	–	–
Riser	9'	10"
Tailpipe	5'	10"

FILTER

Source Colorado

Composition Silica

Gradation 10-20

Inst. method Pour from Top.

Volume used 72-10/20 2-20/40

10/20 Depth 39' to 5' ft.
20/40 5' to 4'

GROUT

Composition silica flour/cement

Volume used chips 4 bag grout ~ 5 gallons

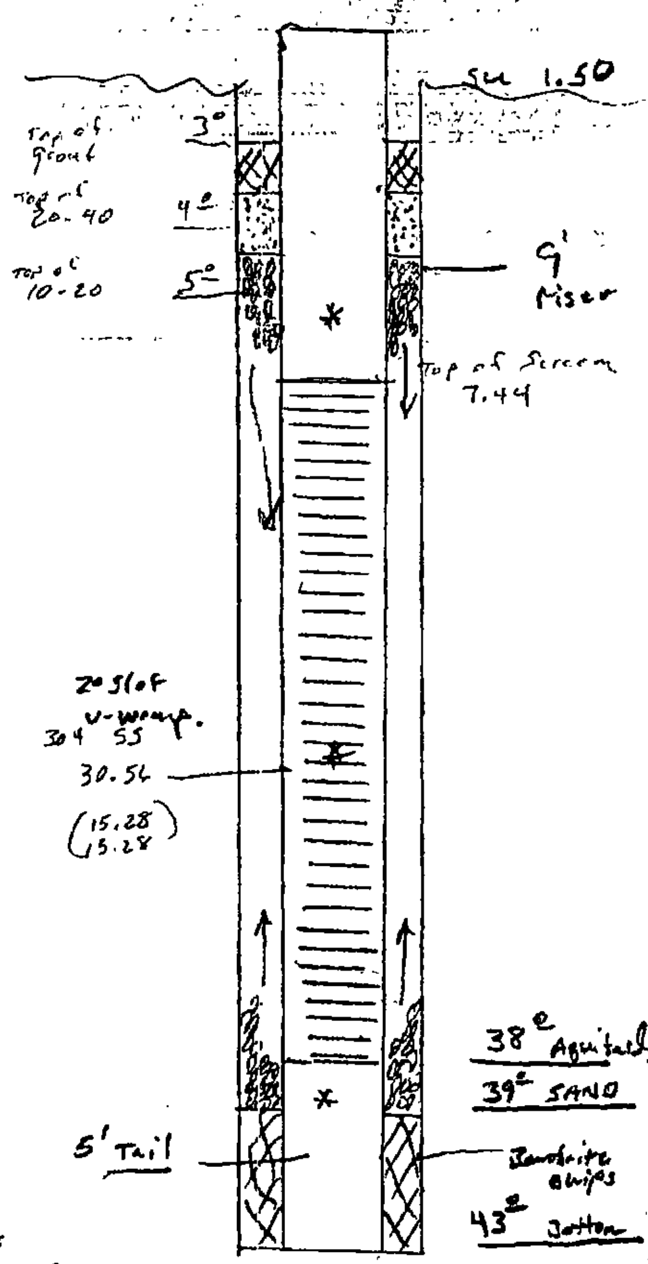
Inst. method pour from top

Depth 3' to 4' ft.

Bentonite chips 43 to 39' ft.

REMARKS:

WELL DETAIL (AS BUILT)



* centralizers 4 per set

44.56 TTL

R 052029

Holt Drilling INC. 112414 **WELL COMPLETION REPORT** Tag # AGN 552
25-2E-35A

Project Wyckoff Well No: E-07
Completion date 10-30-01
Contractor Holt
Rig Stack 71
Operator Wade Everson
Inspector Bob Mumford
Depth 31.5 Datum 69.5

HOLE DATA
Size: 16 in. to ~7 ft.
12 in. to 31.5 ft.
in. to ft.

CASING
Type Steel
Mfr.
Ht. above gnd. surf.
Drive shoe
Size: 16 in. to ~4 ft.
12 in. to 31.5 ft.
in. to ft.

SCREEN
Type 20 slot V-Wrap
Mfr. Johnson
Composition SS Dia. 6"

Fittings:	Length	Dia.
Packer	–	–
Riser	9.5	6"
Tailpipe	5.0	6"

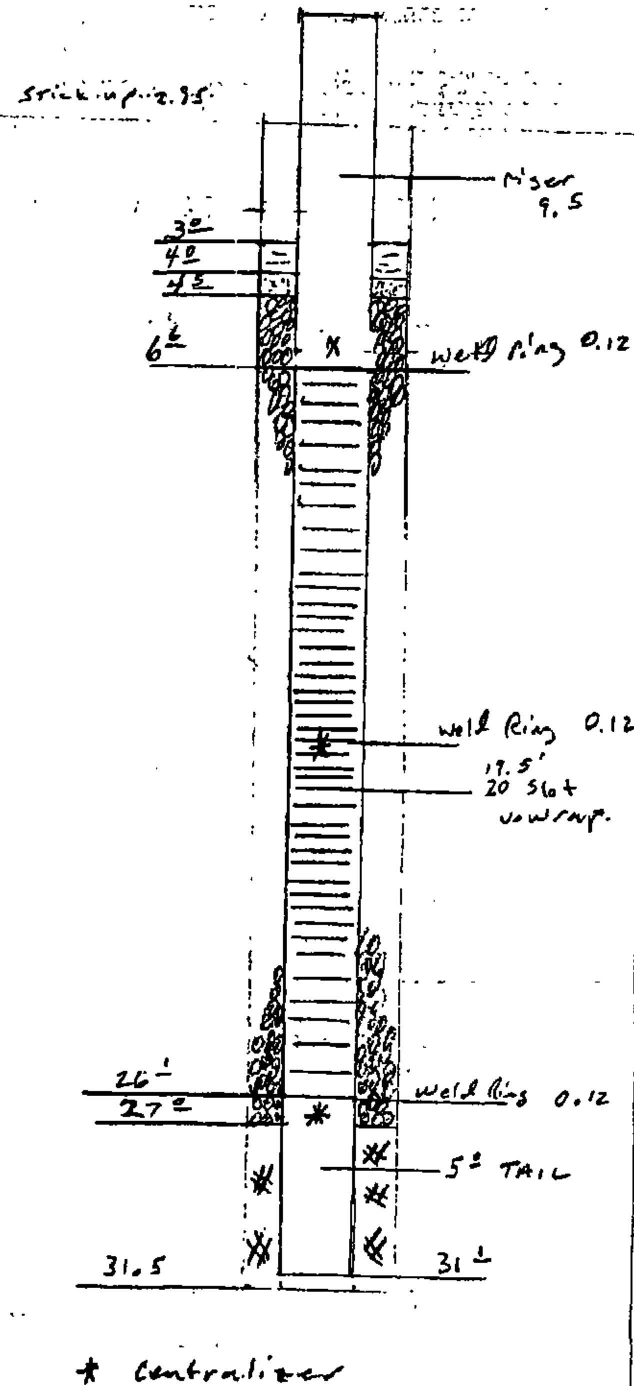
FILTER
Source Colorado
Composition Silica
Gradation 10/20, 20/40
Inst. method Poured from top
Volume used 18 10-20 2 20/40
Depth 27.0 to ft.

GROUT
Composition Silica/Cement
Volume used 5 gallons
Inst. method Poured from top.
Depth 7.0 to 4.0 ft.
Bentonite Chips 31.5 to 27.0 ft.
4 bags

REMARKS:
Centralizer SS 4 per set
3 sets.

Surged well during sand pack
installation.

WELL DETAIL (AS BUILT)



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Attachment B

Wyckoff/Eagle Harbor Superfund Site
Pilot Study Video Inspection – Horizontal Vapor Recovery Piping

Summary

Pipeline Video and Cleaning (Pipeline) videotaped the internal condition of three horizontal vapor recovery pipes (HVRPs) (HV-4, HV-5, and HV-6) in the Wyckoff site pilot study area on July 31, 2003. The HVRP locations are shown in Figure B-1. HV-6 was inspected first, then HV-5 and HV-4. Observations during the inspection indicate that HV-6 had the least amount of visible encrustation in the piping and HV-4 appeared to have the most. In general, more than 90 percent of the horizontal slots in the vapor recovery piping were 100 percent plugged with the naphthalene encrustation. Refer to the Pipeline video (located at the Wyckoff site) for complete visual information. Photos from each of the HVRPs are provided at the end of this appendix (see Figures B-2 through B-9).

Detailed Information

The HV-6 underground piping appeared to be oriented northwest to southeast with the video camera access location in the middle of the pipe. The southeastern part of the piping was videotaped first. Buildup of naphthalene was visible in the pipe and in the pipe perimeter slots. This pipe section showed that approximately 80 percent of the horizontal slots were plugged completely. The camera was pushed to both ends of the pipe.

The HV-5 piping seemed to be oriented northeast to southwest. The northeastern part was videotaped first. The camera experienced resistance to insertion into the pipe that appeared to be caused by naphthalene buildup. Pipeline was able to break through the buildup by forcing the camera through it. The southwestern section was videotaped next. The pipe slots were 100 percent plugged with naphthalene. Some white solid matter was observed in the pipe.

Before the camera could be fed into the access location at HV-4 pipe, Pipeline used a section of small-diameter pipe to break through a naphthalene plug. HV-4 seemed to be oriented northeast to southwest. The northeastern pipe was inspected first. The camera traveled 13 feet to the end of the pipe, where it met the sheet pile wall. The southwestern pipe could not be inspected because of a thick buildup of naphthalene. Pipeline was unable to break through the buildup using the camera. The pipe slots were 100 percent plugged with naphthalene.

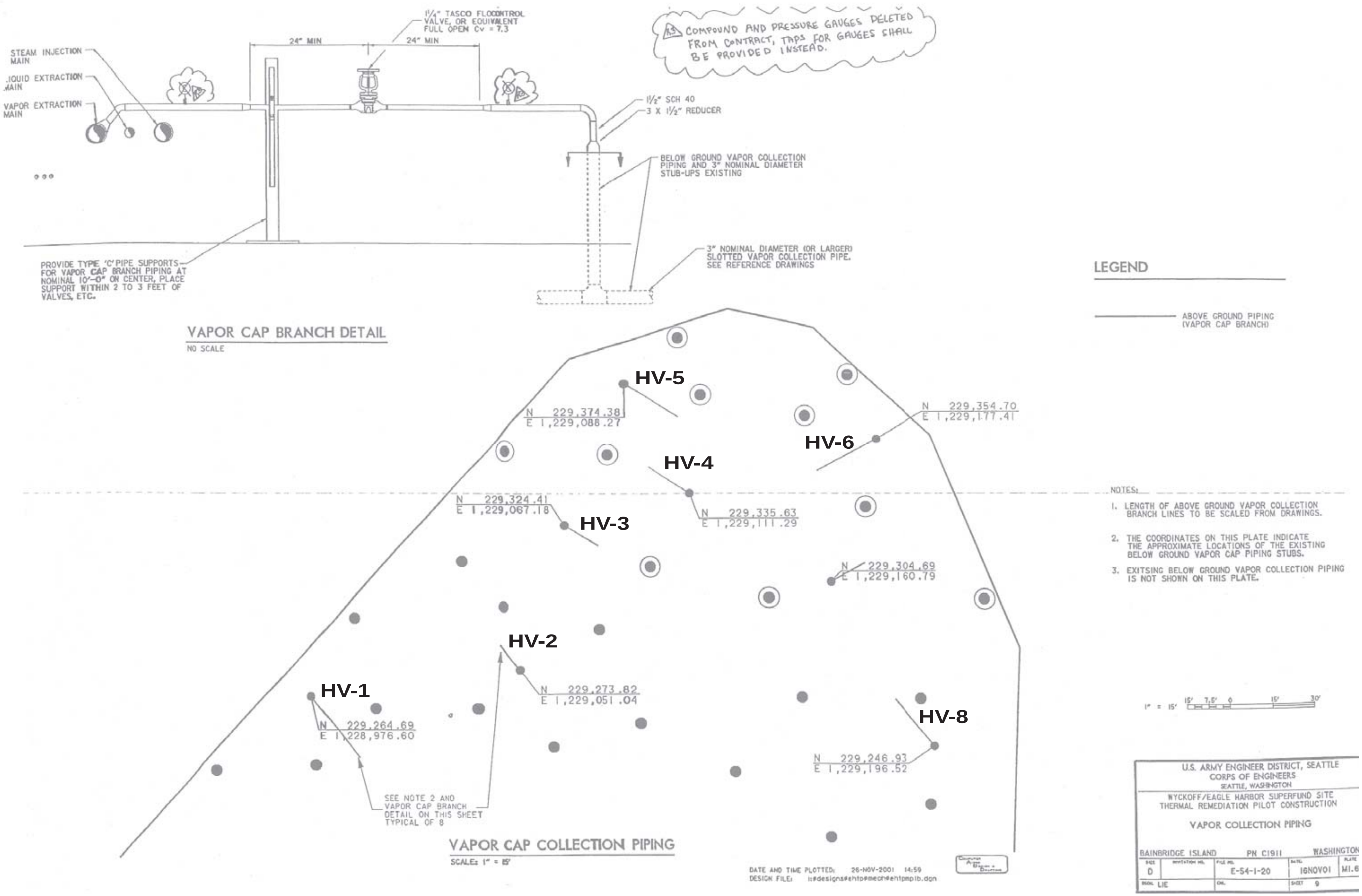

Figure B-1 Vapor Cap Collection Piping

Figure B-2 Wyckoff Horizontal Vapor Recovery Pipe
HV-4 In-ground Piping

Figure B-3 Wyckoff Horizontal Vapor Recovery Pipe
HV-4 In-ground Piping Closeup

Figure B-4 Wyckoff Horizontal Vapor Recovery Pipe
HV-4 In-ground Piping Closeup

Figure B-5 Wyckoff Horizontal Vapor Recovery Pipe
HV-4 Aboveground Piping

Figure B-6 Wyckoff Horizontal Vapor Recovery Pipe
HV-5 In-ground Piping

Figure B-7 Wyckoff Horizontal Vapor Recovery Pipe
HV-5 Aboveground Piping

Figure B-8 Wyckoff Horizontal Vapor Recovery Pipe
HV-6 In-ground Piping

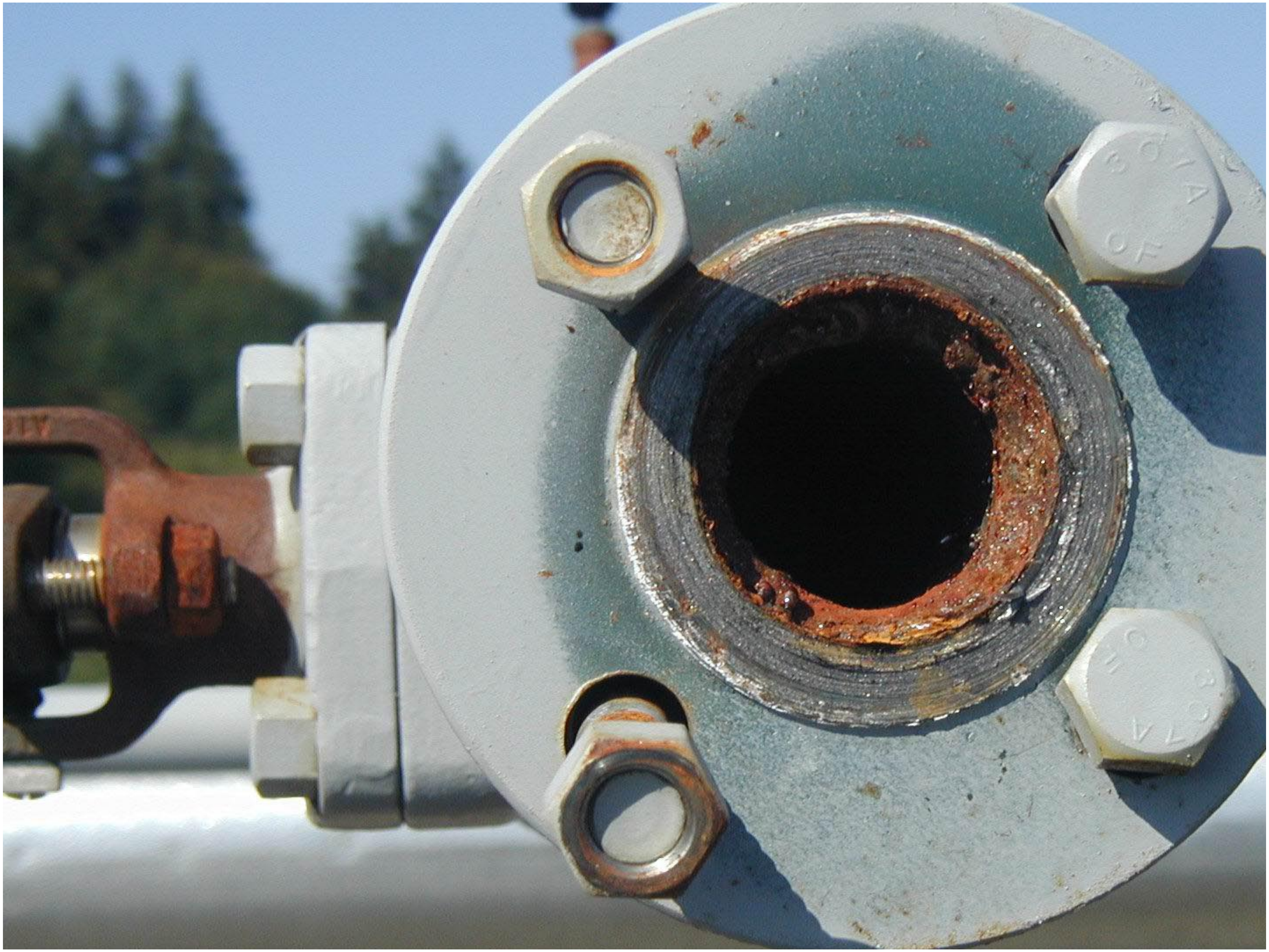

Figure B-9 Wyckoff Horizontal Vapor Recovery Pipe
HV-6 Aboveground Piping

Attachment C

Wyckoff/Eagle Harbor Superfund Site

Pilot Study Area Video Inspection – Extraction Well Inspection

SCS Engineers performed a video inspection of five extraction wells in the Pilot Study Area on August 11, 2003. Inspections were performed on extraction wells E02, E03, E04, E05, and E07. Video inspection was not performed on extraction wells E01 and E06 because the extraction pumps for these wells are still in place. The purpose of the inspections was to assess well screen condition and identify corrosion, encrustation, or other conditions that may be responsible for reduced well yields and to determine the need for well rehabilitation.

The video inspections were performed by lowering a small, lighted video camera down the wells. The camera was tilted at approximately 45 degrees so the casing walls and well screens could be viewed. The image was observed on a monitor at the surface and recorded on a VHS cassette.

In general, the well screens appear to be in good condition with limited evidence of blockage. Extensive naphthalene crystallization was not observed within the screens (unsaturated or saturated zones). Naphthalene crystals were primarily observed inside the well casing above ground surface. Some minor encrustation (possibly biofouling) was observed, however, the most prominent feature observed was product (creosote or related chemicals) globules located in many of the screen openings as well as evidence of product smearing on the screens. In some wells (e.g., E04), significant quantities of sediment had accumulated in the bottom of the well.

The wells were inspected, and appear on the video tape, in the following order: E05, E04, E03, E07, and E02.

Note that the video inspection of E02 was completed in two steps because of the light nonaqueous-phase liquid (LNAPL) layer at the top of the water column. There was a concern that advancing the camera through the LNAPL layer would smear the camera lens and degrade picture quality. The unsaturated portion of the screen was examined first, and the camera was raised before it penetrated the fluid. The camera then was advanced through a conduit inserted through the LNAPL layer. A polyethylene bag was placed on the end of the conduit to prevent LNAPL from entering the conduit. After the conduit was lowered through the LNAPL layer, the camera was forced through the plastic bag to allow filming of the saturated zone of the well while avoiding contact with the LNAPL layer.

SCS recommends re-development of the wells before re-installing the extraction pumps. The development should focus first on removal of sediment and naphthalene crystals (many crystals have fallen from the top where they formed and have settled to the bottom of the well). After the sediment has been cleared, a surging process should be used to clean the actual screens. A well development brush (which has a surging effect in addition to physical agitation) may be particularly effective for this task. Based on the video inspection results, no other rehabilitation measures are called for at this time.

Attachment D

Wyckoff Pilot Study - NAPL Recovery Optimization Conference Call (September 3, 2003)

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FROM: Heidi Blischke/CH2M HILL
Ken Trotman/CH2M HILL

DATE: September 4, 2003

A telephone conference was conducted on September 3, 2003, to discuss: (1) methods to optimize nonaqueous-phase liquid (NAPL) recovery during the continuation of the steam pilot study at the Wyckoff site, and (2) recommendations for placement and operation of extraction well pumps until the steam pilot study is resumed. This document summarizes the conclusions and recommendations developed during the conference call.

The results of the extraction well video work were briefly reviewed. In the inspected wells, the screens did not have obvious signs of plugging by naphthalene crystals, bacterial buildup, or other clogging material. However, precipitated naphthalene crystals were observed inside the well casing at ground surface and above—likely the result of the cooler temperatures in these portions of the wells. The well sumps located below the screen generally contained a mixture of sediment and naphthalene crystals, and/or dense NAPL (DNAPL). Based on the initial review of the video results, the extraction well screens appeared clear, but likely would benefit from standard mechanical redevelopment techniques and sump cleaning. This redevelopment could be done by hand, with a tripod over the wells, or with a boom truck.

When pumping tests were performed with the pump isolated from the aboveground collection system, the extraction wells were able to pump 5 to 10 gallons per minute. Because of uncertainties about well discharge rates, it is not clear whether specific capacity has decreased in extraction wells, with two exceptions. The exceptions, wells E01 and E07, had significant loss of capacity.

Fluid Removal

Following a discussion of pumping equipment, changes in contaminant characteristics during thermal treatment, and approaches to NAPL removal, the preferred fluid recovery system in each extraction well consists of a two-pump system: one QED Hammerhead pump with the pump intake set at the bottom of the well screen and one Slurper pump removing fluid from the top of the fluid column with an adjustable inlet elevation. The following are benefits of the two-pump approach:

- Improved ability to remove both light NAPL (LNAPL) and DNAPL. The QED pump can be controlled to optimize DNAPL recovery while the Slurper pump removes LNAPL from the top of the fluid column. DNAPL recovery can be optimized by maintaining a 5-foot-plus column of fluid above the pump intake to facilitate DNAPL flow paths to the well.
- Redundant pumping capability. Each extraction well has a built-in backup pumping system if one pump fails.
- More pumping capacity to respond to initial water removal requirements during steam injection startup. A two-pump system may require increased compressed air capacity at the site to operate the additional pumps.
- The QED pumps are onsite and ready for use, and the Slurper pump equipment is inexpensive.
- QED pump intake elevation settings will not have to be adjusted during the pilot study. This alleviates the safety concerns associated with adjusting the QED pump settings. The QED pumping rates will be controlled using a throttling device to maintain desired fluid level.

Before installing the two-pump extraction systems, the following actions should be completed:

- Redevelop the extraction wells using physical/mechanical methods (for example, brushing and/or surge block).
- Test the Slurper pump for extraction performance, ease of intake setting adjustment, and degree of product emulsification.
- Confirm ability to adjust QED pump discharge rates.

A phased approach for NAPL removal also was discussed; that is, where NAPL is removed hydraulically followed by dewatering the aquifer and steam remediation. The formation should not be dewatered before restarting the steam pilot study because lowering the groundwater level will cause the NAPL layer to smear downward. This will spread the NAPL in the formation and could reduce its ability to move toward the wells. There is also no value in removing NAPL before the restart of steaming because it will be removed more completely when hot.

Monitoring

From an operational standpoint (total fluids recovery), there does not appear to be a need to collect discrete NAPL layer thickness measurements during the pilot study. The total fluid level in the extraction wells can be monitored using the calibrated pressure transducer currently installed in each well and a measurement of the well vacuum pressure. Because the treatment is aggressive, it was decided that product measurements in wells are not important in understanding system operation or end points of recovery. In fact, it was pointed out that it is difficult to determine the type and quantities of NAPL moving as liquid to the extraction wells based on NAPL volumes removed from the wells. An unknown amount of contaminant is transported in vapor phase and condenses in the vicinity of the extraction well. Measurements of NAPL volumes recovered at the extraction well cannot distinguish between the mobilized liquid phase NAPL and the condensed vapor phase NAPL.

Total extraction system discharge volumes should be recorded noting the presence of LNAPL and DNAPL discharged from each extraction well. Rates of LNAPL and DNAPL recovery will not be monitored because the rates will not determine the end point of the recovery and other methods can be used to monitor whether the system is operating efficiently.

Monitoring for proper system operation includes pressure measurements to determine whether the system is clogging, total fluid pumping rates to understand whether the wells and pumps are operating, and temperatures to understand whether heat is being evenly distributed and if the temperatures are high enough.

Interim Hydraulic Control Measures in Pilot Study Area

During the period until the pilot study is restarted, some hydraulic control pumping will be required to manage vertical hydraulic gradients in the pilot study area during the winter rainy season. The objective is to manage the shallow aquifer heads in order to maintain an upward vertical hydraulic gradient across the underlying aquitard. This will reduce the possibility of dissolved and NAPL contaminant migration through the aquitard.

One extraction well in the pilot study area that is operated during the winter and spring should be sufficient to accomplish this objective. This pump should be set so that it will maintain the desired groundwater elevation using its internal float controls. (Note: For reliability and redundancy, two pumps should be re-installed in the pilot study area and alternated on a regular schedule.)

The number of wells and initial pumping rate(s) should be confirmed using the groundwater flow model currently being developed. Ongoing pumping schedules can be refined during the winter based on water level monitoring data. Pumping volumes should be minimized to maintain temperatures in the pilot study area. Finally, it should be noted that NAPL recovery is not an objective during this interim hydraulic control period.

Attachment 2

Wyckoff - Polynuclear Aromatic Hydrocarbon Influence on System Design

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PREPARED BY:	Jim Mavis/CH2M HILL
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DATE:	August 4, 2003

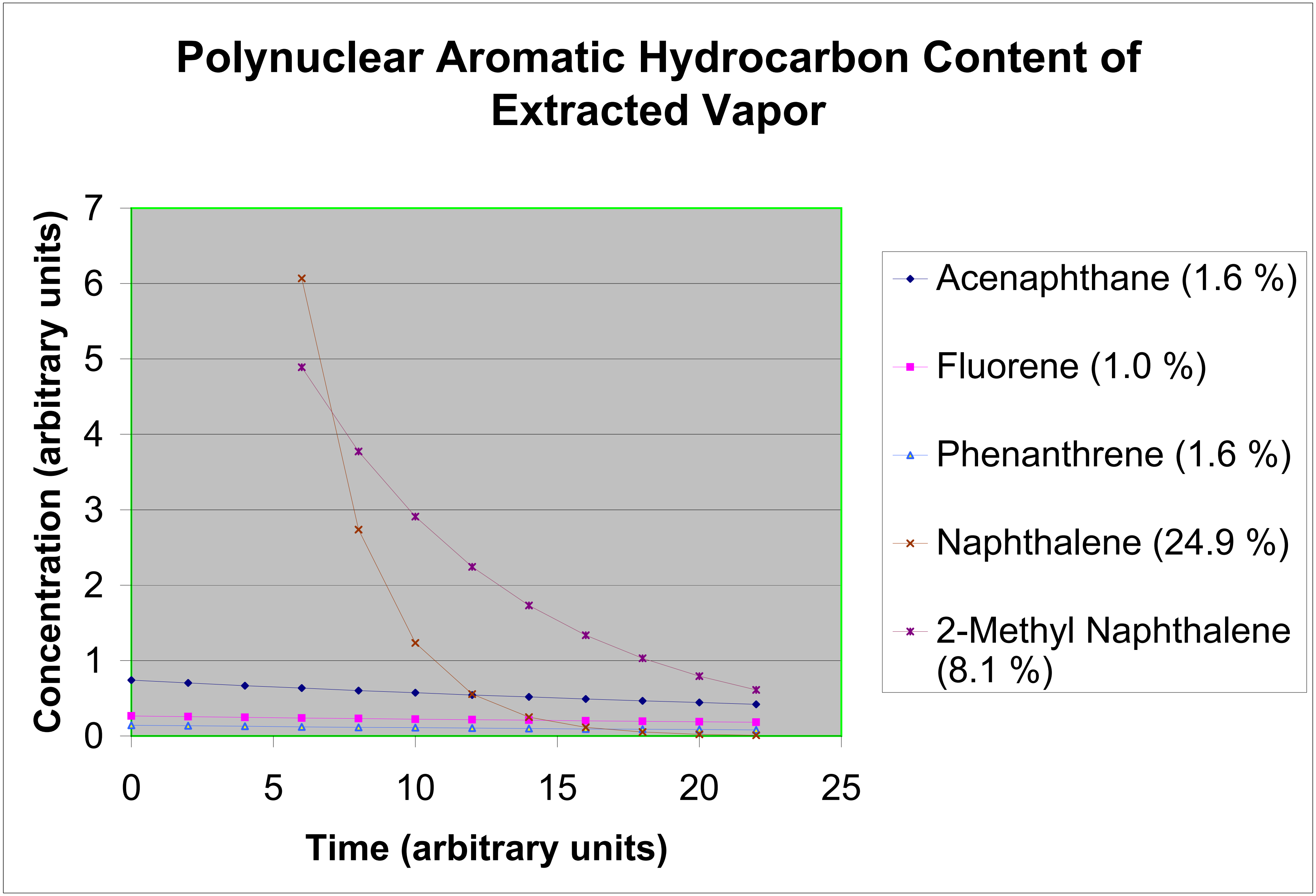
Non-aqueous-phase liquid (NAPL) beneath the Wyckoff Site contains a group of compounds that undergoes direct transition from vapor phase to solids phase, without passing through a liquid phase. This direct transition between vapor and solid phases is known as "sublimation."

Several members of this group of sunlimable compounds occur in Wyckoff NAPL, and all of them are members of a compound class called polynuclear aromatic hydrocarbons (PNAs). Two of these PNAs, naphthalene and 2-methyl naphthalene, comprise 33 percent of the NAPL at the Wyckoff Site, with naphthalene, alone, accounting for nearly 25 percent.

Initial operation of the dynamic underground stripping (DUS) system at the Wyckoff Site has been affected by condensation of solid naphthalene, directly from vapor phase. The naphthalene condensed onto surfaces that were cooler than the temperature of the formation from which the naphthalene originally volatilized. Consequently, upper portions of the wells, aboveground piping, and the tube-in-shell heat exchanger have become partially or completely plugged with solid naphthalene.

The occurrence of naphthalene (and to a lesser extent, 2-methyl naphthalene) has become a critical consideration in designing effective vapor extraction and residue handling subsystems for the Wyckoff Site. Preliminary calculations have shown that, during the early period of operation, naphthalene and 2-methyl naphthalene will be the predominant PNAs in extracted vapor. This is illustrated in the Figure. These two compounds are relatively volatile, however, and they will "decay out" fairly rapidly, leaving much smaller proportions of other, less volatile PNAs in the vapor.

The type of vapor- and solids-handling equipment needed for the initial period of operation during which naphthalene (and 2-methyl naphthalene) are the dominant constituents in the extracted vapor stream needs to be selected with the physical properties of these sublimable constituents in mind. As an example, all vapor lines upstream of the liquid ring vacuum pump(s) will need to be heat traced to prevent deposition of naphthalene and 2-methyl naphthalene. And a different type of heat exchanger (one that acts as a condenser) will be needed to permit sustained operation of the vapor extraction system.



Polynuclear Aromatic Hydrocarbon Content of Extracted Vapor
Concentration (arbitrary units)
Time (arbitrary units)
0
1
2
3
4
5
6
7
0
5
10
15
20
25
Acenaphthane (1.6 %)
Fluorene (1.0 %)
Phenanthrene (1.6 %)
Naphthalene (24.9 %)
2-Methyl Naphthalene (8.1 %)

Attachment 3

Wyckoff Site - Vapor Extraction during Vacuum Tests

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DATE: August 1, 2003

We have just finished making preliminary, conservative estimates of the vapor extraction rate during vacuum testing of the 7 extraction wells at the Wyckoff Site. Estimates have been made for 11 of the 17 polynuclear aromatic (PNA) compounds that were previously identified in NAPL samples (*Comprehensive Report – Wyckoff NAPL Field Exploration*, USACE for USEPA, May 2000).

The remaining 6 PNAs were not included in the calculations because information relating vapor pressure to temperature (Antoine's equation constants for each compound) was not available. The compounds for which vapor pressure information was not located were acenaphthylene, benzo(a)pyrene, benzo(k)fluoranthene, chrysene, dibenzofuran and indeno(1,2,3-cd)pyrene.

Lack of information for most of these missing compounds would not result in measurable change in vapor composition. The only compound that might be detected would be acenaphthylene, but its concentration in the NAPL is low, and excluding it would not result in any changes to the project.

Assumptions

The extraction estimates were based on several assumptions that make the total mass extraction rate of hydrocarbon compounds conservatively high. Key assumptions are as follows:

- The ~37.5-percent fraction of NAPL that remained unidentified after characterization was assumed to resemble No. 2 fuel oil in chemical composition. (This assumption is reasonable for the "light aromatic oil" that was used with pentachlorophenol. Bunker C was used as the carrier for creosote. The No. 2 fuel oil assumption probably results in an overestimation of the total hydrocarbon content of extracted vapor, because No. 2 fuel oil contains more lower-boiling constituents than does Bunker C, as reported by a former Wyckoff employee.)
- The temperatures in all 7 wells is assumed to be ~140 °F. (Actual temperatures in these wells range from ~100 °F to ~145 °F, so we have used 140 °F as the nominal temperature

after the well begins to be evacuated and the vapor pressure and consequently the temperature decrease because of gas expansion.)

- The heat exchanger upstream of the liquid ring vacuum pump(s) will reduce the vapor temperature to 80 °F. (This is conservative because it represents a 25-degree F approach temperature in the heat exchanger, whereas 15 to 20 degrees would be more typical. The higher the final vapor temperature, the more hydrocarbon mass remains in the vapor phase to be removed in downstream processes.)

Operating Conditions and Variables

Table 1 shows the predicted vapor composition at two different vapor extraction rates from onsite wells, - 450 standard (1 atmosphere, absolute and 60 °F) cubic feet per minute (scfm) and 225 scfm, and at two vapor temperatures, - 140 °F and 80 °F. The higher extraction rate, 450 scfm, would occur when a liquid ring pump is pulling from a well as its only source of gas or vapor. The lower extraction rate is intended to simulate the average vapor extraction rate over the course of the vacuum tests: part of the time, the pump suction will receive a mixture of air and of vapor from a well, in order to control the absolute pressure within a well.

The higher temperature, 140 °F, occurs within the well and in the extracted vapor before it is cooled in the heat exchanger (which acts as a condenser). The lower temperature, 80 °F, would be the temperature of the vapor stream at the outlet from the heat exchanger, after vapors that can condense as liquids or solids have been removed.

Hydrocarbon Mass Flow Rate Estimates

Table 1 provides a conservative estimate of the mass of hydrocarbon compounds that will be extracted during well vacuum testing. At full–flow vapor extraction (450 acfm and 140 °F), the total predicted hydrocarbon mass flow rate is 35.67 lb/hr. This rate is high-biased because light oil was assumed for the carrier liquid (the unidentified ~37.5 percent of the NAPL), and because vapor pressure information (Antione equation constants) was only available for only a few lower-boiling compounds. While not completely circumventing the lack of information on vapor pressures, we incorporated compounds (1-methylpropyl cyclohexane and tetralin) that are representative of two of the classes normally found in No. 2 fuel oil. We assumed these two compounds were present to give better estimates of concentrations of "compounds of concern" whose vapor phase contributions we are interested in. If "Antoine constants" are located at a later date, they can be incorporated into the spreadsheet.

Although the "recipe" for NAPL was based on analyses of samples, there may be significant omissions that could affect the operation of process equipment downstream of the vapor extraction pumps. So far, there has been no report of testing for low molecular weight hydrocarbon compounds such as methane, ethane and other gases that often occur in hydrocarbon-contaminated sites. If some of these compounds are present at significant concentrations, the design of downstream equipment could be affected and sizing of thermal oxidizers could be impacted by excess "fuel value" in the off-gas. Specific analyses for potentially relevant constituents are recommended below.

Vapor Extraction Rates

Upon cooling the 450 acfm vapor stream down from 140 °F to 80 °F, about 87 percent of the hydrocarbon compounds condense-out, leaving about 5.18 lb/hr of residual hydrocarbon content in the vapor. Again, this may be a high-biased estimate, because of our inclusion of 1-methyl propylcyclohexane and tetralin into the "recipe," which together contribute 2.64 lb/hr of the predicted 5.18 lb/hr hydrocarbon mass flow.

When air is bled into the vacuum suction at half the volumetric rate at which vapor is being extracted from the wells, the hydrocarbon mass flow rates drop exactly in half. The volumetric extraction rate from the well(s) is reduced to 225 acfm, and the hydrocarbon mass flow rates are also reduced by half, to ~17.83 lb/hr at 140 °F from the wells, and 2.59 lb/hr at 80 °F from the heat exchanger.

Input Variables

The spreadsheet has been set up to estimate vapor mass flow rates at selected temperatures (°F), pressures (at the vacuum pump suction header) (atmospheres), and volumetric flow rates (acfm). Using these three input parameters (and without manually altering the hydrocarbon mixture in NAPL phase), hydrocarbon vapor compositions in equilibrium with "average" NAPL can be estimated.

Sublimation

Table 1 also identifies several compounds that undergo "sublimation" (converting directly between solid phase to vapor phase, without passing through an intermediate liquid phase). Naphthalene is the highest-concentration compound in NAPL that exhibits this characteristic (9.2 lb/hr at 450 acfm and 140 °F), followed by 2-methyl naphthalene (1.33 lb/hr), acenaphthene (0.1 lb/hr), fluorene (0.032 lb/hr), and anthracene (0.00032 lb/hr). (Fluoranthene and pyrene also sublime, but the combination of their low concentration in NAPL and their high vapor pressure, – both reportedly sublime under vacuum, relegate them to near-insignificance at the Wyckoff Site.)

Vacuum Pump Suction Pressure Variation

The spreadsheet has been constructed to estimate the individual temperature-dependent vapor pressure contributions at equilibrium from each identified hydrocarbon compound and the temperature-dependent vapor pressure of water, and calculate the subtotal of these two vapor pressures. If the subtotal of the hydrocarbon vapor pressure and the water vapor pressure is less than one atmosphere, the balance of the pressure to reach one atmosphere is assumed to be air (oxygen and nitrogen). Air is "added" computationally to bring the sum of the partial pressures to 1.0 atmosphere. If the sum of the partial pressures is one atmosphere or more, the spreadsheet does not include air among the components of extracted (or cooled) vapor.

Vapor Compositions

The spreadsheet predictions shown in Table 1 may be used as estimates of the vapor compositions at the extraction wellheads, at 140 °F, and after the heat exchanger, at 80 °F. The heat exchanger vapor exhaust stream may be used as an estimate of the <u>composition</u> of feed to any of the off-gas control devices (or techniques) during vacuum testing or during actual pilot testing.

The mass flow rate depends on the mode of operation during any particular period of pilot testing. Variations in composition will occur when fluctuations of cooling water temperature or flow, or fluctuations in wellhead vapor temperature are experienced.

Other Issues

Odors

Naphthalene and other hydrocarbon compounds have strong, distinctive odors that need to be considered in designing and operating the pilot system at the Wyckoff Site. The information in Table 1 can be used to assess the potential significance of nuisance odors from the Site. The potential for odor problems will be addressed in a separate memorandum.

Health and Safety

Health

The time-weighted average exposure for naphthalene is 10 ppmv according to NIOSH guidelines. The estimate for naphthalene in vapor from the heat exchanger exhaust at 80 °F is ~113 ppmv, or over 10-times the OSHA limit. This means that workers in the area will need to be protected from naphthalene vapor during conduct of the vacuum tests.

Other compounds that have OSHA criteria may also be present. However, at present, naphthalene is the dominant compound of concern, and addressing it should also provide protection from many others as well.

Safety

Sampling to date has focused on known and suspected contaminants that are related to wood-preserving activities at the Site. The specific compounds characterized are solids, liquids, or liquid carriers for the solids and liquids used in wood preservation that have contaminate surface and subsurface soils.

In the environment, many of the compounds among the contaminants, and in the carrier liquids may undergo biological degradation and generate lower molecular weight by-products, including gases such as methane. To our knowledge, no analyses have been performed for any of potential breakdown products or combustible gases.

If present, gases such as methane could create several problems, ranging from creating combustible mixtures in process piping and equipment, and overloading organic destruction equipment such as thermal oxidizers, which have maximum rated capacities for combustible compounds in the influent.

We are raising this as an issue that should be considered, and appropriate precautions should be taken to prevent unexpected problems.

Recommendation

Because of uncertainties about the completeness of vapor characterization, especially the possible presence of combustible gases, we recommend that several vapor samples be analyzed during the upcoming vacuum tests. Samples should be taken both of hot vapor from the suction side of the vacuum pump, and downstream of the heat exchanger, after much of the water and high-boiling organic material has condensed.

The analyses should include the suite of sublimable polynuclear aromatic hydrocarbon compounds, low molecular weight gases of one, two three and four-carbon structures, as well as full a suite of heavier aromatic and aliphatic compounds as may be within the capability of the laboratory. Specific target compounds would be suggested after consulting previous investigators who have experience with the Site and candidate laboratories, where the analyses might be performed.

Attachment 4

Wyckoff - Extracted Vapor Processing during Dynamic Underground Stripping

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Mark Davis/SEA

DATE: April 23, 2004

Background

Preliminary operation of the dynamic underground stripping (DUS) pilot system uncovered unexpected difficulties with the aboveground vapor handling system. The principal problems were related to pipe, equipment, and probably subsurface formation plugging by a naphthalene-rich organic phase.

Naphthalene exhibits an unusual behavior called sublimation, which means it can condense from vapor phase, directly into solid phase. This property, accompanied by condensation of other organic vapors into liquid phase, caused the plugging problem.

The composition of extracted vapor was not measured during preliminary pilot system operations. However, estimates of vapor composition as a function of temperature were developed from available chemical analyses of non-aqueous phase liquid (NAPL) analyses, and reasonable assumptions about other constituents that are likely to be present in the prepared creosote-solvent solution. These calculated compositions were used to develop an improved conceptual design for managing extracted vapor in aboveground facilities.

The conceptual design is summarized in four sections in the memorandum:

- Vapor Composition and Flow Rate
- Aboveground Vapor Management
- Major Equipment
- Startup Considerations.

This memorandum describes an aboveground treatment system that should overcome the difficulties that were encountered during preliminary operations. The process was only developed at the conceptual level and has not been tested. No sensitivity analysis or failure mode analysis is typically performed at the conceptual level, leaving these functions to be carried out later in the engineering design process.

Vapor Composition and Flow Rate

Vapor Composition

The composition of vapor in the subsurface formation varies as a function of temperature. The actual composition was not measured. But an estimated composition was constructed from site-specific chemical characterizations NAPL, published accounts of No. 2 fuel oil, published physical properties of the NAPL constituents, and the physical properties of the organic components and chemical and physical properties of water and air. (Air was assumed to make up any missing volume needed to reach 1.000 atmosphere total pressure after summing the partial pressures of individual constituents. The vapor phase was assumed to be saturated with water vapor at any given temperature.)

The vapor flow rate was based on the combined capacities of the two existing vapor extraction pumps. The vacuum extraction pumps are placed downstream from a vapor condenser in the process concept (see Process Schematic that accompanies this memorandum). Each pump is rated at 450 actual cubic feet per minute (acfm), and their combined capacity is ~800 acfm. Consequently, the vapor that is extracted from the ground is condensed to reduce the volumes of water vapor and condensable organic compounds, and the resulting vapor from the condenser has a volumetric flow rate of 800 acfm.

Table 1 shows the estimated mass flow rates of organic constituents, water vapor and air at three temperatures, 210° F, 185° F and 100° F. These vapor temperatures span the range that could be encountered during initial subsurface heating. Note that the flow rates are normalized to 800 acfm <u>from the point of extraction from below ground</u> in order to provide a direct comparison. These compositions are indicative of what is expected during the startup phase of operation, and not at steady state once the subsurface has been heated to its final temperature.

The composition at 210° F is the saturated steam-plus-organic temperature at 1 atmosphere (14.7 psia). The small concentration of air was added to raise the sum of the constituent partial pressures to exactly 1.000 atmosphere (atm). This will be the temperature at the extraction wellhead(s) during steady-state operation of the DUS system. The composition at 185° F is shown because it is above the temperature at which naphthalene solidifies (176° F), and consequently, has been chosen as the operating temperature of the revised aboveground vapor-handling system.

Note that the actual total <u>mass</u> flow rates at 185° F and 100° F would be significantly smaller than those shown in Table 1 but the air <u>mass</u> would remain constant, as the vapor passes through the condenser and moves on through the aboveground vapor treatment system.

Vapor Flow Rate

"Normalized" Flow Rate (for Comparison Purposes)

During DUS operation at steady state, vapor vented from underground will have the approximate relative composition shown in Table 1. There is uncertainty in estimating the amount of air that will be present in the vapor, since the subsurface formation will be maintained at a slight vacuum. Consequently, it necessary to make some assumptions in order to describe above ground vapor treatment system. The main assumptions for steady state operation are,

- The existing cap over the pilot test area will be effectively sealed to prevent extensive air in-leakage.

Table 1. Summary of Vapor Composition during DUS at Three Extraction Temperatures and 800 acfm

Temperature °F	Constituents		Flow Rate lb/hr
100	Organics	Total	17.8
		PNAs	4.6
		Benzenes, Aliphatics, Tetralins	13.2
		Methane	(unknown)
	Water Vapor		131.5
	Air		3,043
185	Organics	Total	197
		PNAs	69
		Benzenes, Aliphatics, Tetralins	128
		Methane	(unknown)
	Water Vapor		1,010
	Air		1,169
210	Organics	Total	349
		PNAs	129
		Benzenes, Aliphatics, Tetralins	219
		Methane	(unknown)
	Water Vapor		1,642
	Air		19.6

- Vapor extracted from the subsurface will contain a small quantity of air sufficient to raise the total vapor pressure to 1.000 atmosphere at 210° F.

- The volumetric vapor flow rate downstream of the vapor condenser/knockout tank will be 800 acfm, which “fixes” the total vapor extraction rate from the subsurface.

- The thermal oxidizer will be upgraded to accommodate 800 acfm of vapor from the condenser/knockout tank.

Process Flow Rate (during Routine Operation)

The 800 acfm vapor flow rate is fixed by the design of the liquid ring vacuum pumps, and is irrespective of the vapor temperature or absolute pressure. These vacuum pumps are located downstream of the vapor condenser/knockout tank and will be pumping vapor after about half of the water vapor and organic compounds have been removed by cooling the extracted vapor stream down to 185° F (see Process Schematic).

For the volumetric flow rate of 800 acfm at 185° F downstream of the vapor condenser/knockout tank, the volumetric flow rate extracted from the subsurface formation in the pilot test area will be 1,348 acfm. The difference between 1,348 acfm and 800 acfm (548 acfm) is the volume of vapor that condenses out in the direct contact condenser as liquid water (~41 percent volume reduction) and liquid organic matter (~44 percent reduction), including liquid naphthalene. Condensation to a lower temperature, say below ~176° F would result in naphthalene condensing directly into solid phase (some becoming dissolved in the condensed liquid organic phase.

After the vapor is cooled to 185° F, the composition will change because organic constituents and water vapor will condense in a new direct contact condenser. The 800 acfm vapor volume from the condenser/knockout tank is then sent to the thermal oxidizer, downstream. Feed to the thermal oxidizer will have approximately the composition shown in Table 2.

Above Ground Vapor Management Process

Preliminary operation of the DUS pilot unit at the Wyckoff site showed that naphthalene was being extracted in higher concentrations than might have been anticipated. The high naphthalene content proved difficult to process because it condensed directly to a solid and plugged vapor piping and equipment.

Recognizing these difficulties led to a revision of the design that would overcome plugging while permitting treatment and management of the recovered vapor stream. The redesign took into account the sizes and capacities of existing equipment, while addressing the overall goals of the pilot test. In addition to revising the equipment types and configurations, startup strategies are also needed. Specifically, it assumed that until the majority of the subsurface formation is above the solidification temperature of naphthalene (176° F), steam will be injected and withdrawn through the same injection lines, to raise the formation temperature for sustainable operation.

The revised design is shown in the Process Schematic accompanying this memorandum. The initial requirement for successful above ground processing is to convey hot vapor to the process equipment without plugging the lines and ducts. To facilitate vapor transfer, the vapor conveyance lines will be heat-traced and insulated to maintain pipe wall temperatures above the solidification point of naphthalene, i.e., >>176° F, probably in the range of 205° F or higher to avoid liquid condensation in the lines.

Table 2. Vapor Composition Downstream of Direct Contact Condenser at 185° F

Component	Vapor Partial Pressure, volume-fraction
Water Vapor	962,803
Air	12,123
2-Methyl Naphthalene	1,081
Acenaphthene	71
Fluorene	22
Naphthalene	7,762
o-Xylene	222
Pentachlorophenol	0.145
Phenanthrene	11
1,3,5-Trimethyl Benzene	1,672
n-Butyl Benzene	1,522
1,2,3,4-Tetramethyl Benzene	918
1-Methylpropyl Cyclohexane	9,149
Tetralin	1,531
n-Decane	431
n-Undecane	308
n-Dodecane	167
n-Tridecane	101
n-Tetradecane	56
n-Pentadecane	27
n-Hexadecane	12
n-Heptadecane	7
n-Octadecane	3
Total	1,000,000

Process Description

The existing tube-in-shell condenser (vertically oriented heat exchanger) at the Wyckoff Site became plugged during initial operation of the DUS system. The revised design utilizes this vertically oriented heat exchanger to remove heat from a new direct contact condenser.

Vapor Line Heat Tracing

In the revised configuration, vapor from the subsurface formation is conveyed through heat traced lines to a new direct contact vapor condenser. The temperature in the direct contact condenser is maintained above the solidification point of naphthalene (>176° F) to prevent plugging and general fouling of downstream equipment.

Direct Contact Condenser

The new direct contact condenser and the existing vertical heat exchanger both operate at ~180° F (circulating liquid) to 185° F (residual vapor after condensation) as shown in the Process Schematic. Vapor is condensed as a two-phase liquid (aqueous and organic), by direct contact between the incoming vapor and circulating cooling water. The circulating water stream drops from the direct contact condenser into an oil-water separator, where the floating oil phase is decanted and the denser aqueous phase is circulated through the (existing) vertical heat exchanger and back to the direct contact condenser.

Oil-Water Separator

The oil phase from the oil-water separator is pumped to a product recovery tank for off-site disposal. All oil-bearing lines and equipment are heat traced to keep the temperature above naphthalene's solidification temperature (176° F).

The denser aqueous phase is pumped back through the vertical heat exchanger, except for a small bleed stream, needed to maintain the overall water balance through the condensing loop.

Vertical Heat Exchanger

In the vertical tube-and-shell heat exchanger, the cooling water temperature drops from ~185° F to ≥ 177° F, above the solidification point of naphthalene. Cooling water on the shell side of the vertical heat exchanger is supplied by an evaporative cooling tower. To avoid cooling the circulating water in the direct contact condenser to the point that naphthalene might crystallize in the direct contact condenser, a portion of the heated shell-side cooling water is recycled and a relatively small supply of cool makeup water is to maintain the water balance.

Condensate Blowdown

Accumulated aqueous-phase liquid must be blown down from the circulating water of the vapor condensation system to maintain the water balance. The condensate blowdown stream mixes with extracted groundwater and is discharged through a heat exchanger to cool the combined stream to ~95° F or below for compatibility with the treatment system.

(Two groundwater heat exchangers will be installed. One heat exchanger will be in operation while organic foulants are being removed from the other.)

Condenser Vapor Line and Duct Heater

Cooled vapor is pulled from the direct contact condenser by the two liquid ring vacuum pumps at a rate of 800 acfm. The condenser vent line is heat traced to prevent naphthalene and any other condensable materials from condensing in the vapor duct as the vapor flows to the thermal destruction unit. It is essential to maintain condensation-free feed to the thermal oxidizer to avoid damaging the refractory by thermal shocking, so a duct heater will be installed in the vapor line to keep the vapor above its dew point.

Major Equipment

Major equipment falls into two categories, existing equipment and purchased new equipment.

Existing Equipment

Existing equipment available from the initial steam trials consists of HX3, the existing Extracted Vapor Cooler (vertically mounted tube-in-shell heat exchanger) and two Travani Liquid Ring Vacuum Pumps. (The Thermal Oxidizer, recently upgraded for operation at 500 scfm, has too low a volumetric capacity for operation at current design conditions, and it is unsuited for upgrading to operate at higher capacity.)

New Equipment

Major equipment purchases needed to provide an operable aboveground vapor handling system consist of,

- A Direct Contact Cooler (vapor condenser)
- An Oil-Water Separator
- A Thermal Oxidizer
- A Cooling Tower (serving both vapor condenser and extracted groundwater)
- Condenser Vapor Duct Heater

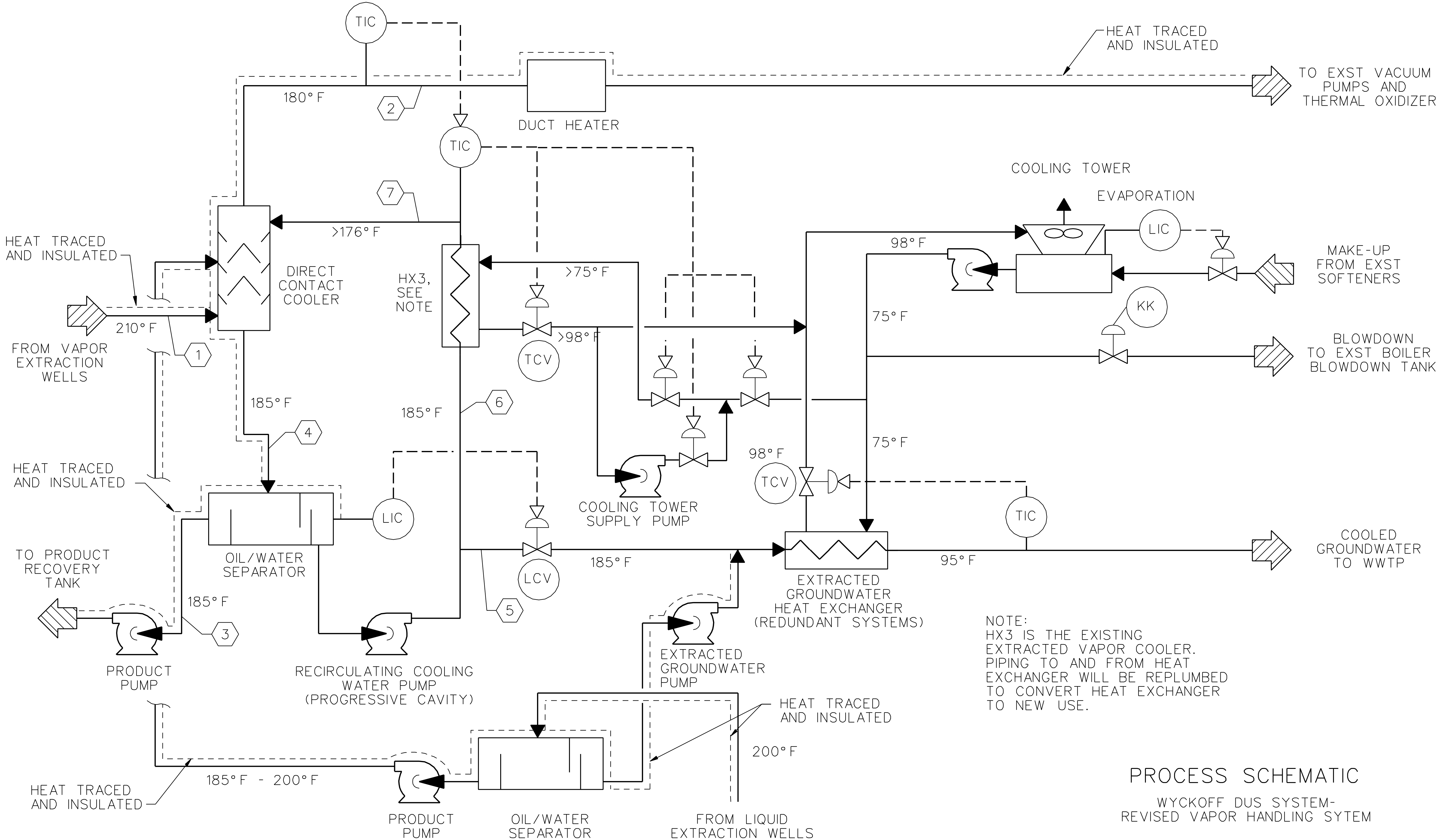
A variety of smaller equipment and system modifications are also needed for successful operation of the aboveground vapor management system. These additional requirements are not further described in the current memorandum.

Startup Considerations

The subsurface formation underwent plugging as naphthalene vapor migrated in the heated front and recondensed as a solid in lower temperature zones. A different startup strategy is needed to avoid similar occurrences in the future.

The startup strategy that was chosen is injection and vapor extraction from the same wells and vents, until the vapor temperature from each well and vent exceeds ~176 to 180° F. After the extraction temperature is above the temperature at which naphthalene is in the vapor phase, normal steam injection would begin into the injection wells, and vents would receive injection steam only periodically. After steady state steam injection is initiated, vent temperatures are expected to temporarily decrease as the vapor gradually heats isolated cooler zones.

Eventually, the steady state extraction temperatures of the vents will stabilize above the point at which naphthalene would block the formation with solids, and the overall system can be operated with continuous steam injection and vapor extraction.



PROCESS SCHEMATIC

WYCKOFF DUS SYSTEM-
REVISED VAPOR HANDLING SYTEM

CH2MHILL

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